



April 7, 2021

BY ELECTRONIC FILING

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

Re: Joint Filing of ISO New England Inc. and New England Power Pool Regarding Offer Review Trigger Prices; Docket No. ER21-___-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, ISO New England Inc. (the "ISO"), joined by the New England Power Pool ("NEPOOL") Participants Committee, hereby submits with this cover transmittal letter two alternative versions of Tariff changes to establish Offer Review Trigger Prices ("ORTPs") for the sixteenth Forward Capacity Auction ("FCA 16").¹ One version is advocated by the ISO, the other by NEPOOL. Together, the ISO and NEPOOL join in asking the Commission to choose between these two alternatives or, as explained below, to adopt any or all portions of either proposal that it finds to be just and reasonable and preferable. Both the ISO and NEPOOL request that the Commission issue an order in this proceeding on or before Tuesday, June 8, 2021.

The ISO and NEPOOL proposals are being submitted pursuant to Section 11.1.5 of the Participants Agreement (referred to as the "jump ball provision").² Section 11.1.5 requires that the ISO, as part of a Section 205 filing, present to the Commission any alternative Market Rule proposal that is approved by a Participant Vote of at least 60 percent, describe in sufficient detail to permit reasonable review by the Commission, explain the ISO's reasons for not adopting the proposal, and provide an explanation as to why the ISO believes its own proposal is superior to the proposal approved by the NEPOOL Participants Committee. The Commission may choose to "adopt any or all of ISO's Market Rule proposal or the alternate Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable." The Commission, under this Section 205 "jump ball" filing, may adopt any or all components of either the ISO or NEPOOL

¹ Capitalized terms used but not defined in this response are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff ("Tariff").

² See Participants Agreement § 11.1.5, available at http://nepool.com/uploads/Op-PA.pdf.

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proposals without needing to consider any other alternative that may be presented by an intervenor in this proceeding.³

The primary differences between the two proposals as they relate to specific ORTP values are for three technology-types—off-shore wind, photovoltaic solar, and battery storage. For these technology-types, the NEPOOL proposal includes lower values than the ISO proposal, based on NEPOOL's proposed change to the Tariff that would require the ISO to account for each technology's "economic life," and/or based on different modeling assumptions. The remaining components of the NEPOOL Alternative that differ from the ISO's proposal are explained fully in NEPOOL's transmittal letter and supporting materials, which are all attached to this joint cover letter.

It is important to underscore that this filing of ORTP values for FCA 16 is mandated by the terms of the ISO-NE Tariff. Absent a Commission order accepting new ORTP values for each technology that is participating in the Forward Capacity Market, the ISO cannot move forward with the administration of FCA 16. The ISO explains in its transmittal letter why an order by June 8, 2021 accepting new ORTP values is necessary for ISO-NE to move forward with FCA 16 qualification and to avoid a delay in carrying out the auction in February of 2022.

The ISO Materials Submitted for this Filing

The ISO is submitting materials in Attachments I-1a through I-1-1k include: (a) a transmittal letter explaining the ISO's proposed Tariff changes, (b) the December 2020 Report from Concentric Energy Advisors and Mott MacDonald, Inc. describing its analysis supporting the ISO's proposal, (c) a March 2021 Addendum to the December Report regarding updates to the Cost of New Entry calculations submitted to the Commission in Docket ER21-787, (d) an April 2021 Addendum to the December Report regarding updates to the Offer Review Trigger Price calculations due to recent tax law changes, (e) a Report from Mott MacDonald regarding its Offshore Wind ORTP Analysis, (f) Testimony from Danielle S. Powers of Concentric Energy Advisors, (g) Affidavit of Danielle S. Powers of Concentric Energy Advisors, (h) Affidavit of Keith Paul of Mott MacDonald, (i) blacklined Tariff sheets reflecting the ISO proposal, (j) clean Tariff sheets reflecting the ISO proposal, and (k) a 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. In its materials, the ISO satisfies the requirements in the jump ball provision by explaining the ISO's reasons for not adopting the NEPOOL proposal and by providing an explanation as to why the ISO's proposal is superior to the NEPOOL proposal.

The NEPOOL Materials Submitted for this Filing

The NEPOOL materials contained in Attachments N-1a through N-1j include: (a) the NEPOOL transmittal letter containing an explanation of the NEPOOL proposal, including a

³ Cf. Southern California Edison Co., et al, 73 FERC ¶ 61,219 at 61,608 n.73 (1995) (citing Cities of Bethany et al.

v. FERC, 727 F.2d 1131, 1136 (D.C. Cir.)).

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discussion of why the NEPOOL proposal is preferable to the ISO proposal and should be accepted by the Commission; (b) Testimony from Abigail Krich of Boreas Renewables, including Appendices A and B, (c) Testimony from Carolyn Gilbert of Daymark Energy Advisors, including Appendices A and B, (d) Joint Testimony from Elizabeth Delaney of Borrego Solar Systems, Inc. and Michael Macrae of Enel X North America, (e) Affidavit of Benjamin W. Griffiths of the Massachusetts Attorney General's Office, including Appendix A, (f) Testimony from Sarah Bresolin Silver of ENGIE North America Inc., (g) a Summary of the NEPOOL Participant Processes, (h) the March 24, 2021 NEPOOL Participants Committee Vote Tabulation, (i) blacklined Tariff changes reflecting the NEPOOL proposal, and (j) clean Tariff changes reflecting the NEPOOL proposal.

Following this letter is a Table of Contents listing each attachment to this filing.

Respectfully submitted,

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ISO-NE Transmittal Letter



April 7, 2021

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 Forward Capacity Market Offer Review Trigger Prices

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act and Section III.A.21.1.2(a) of the ISO New England Transmission, Markets and Services Tariff (the "Tariff"),¹ ISO New England Inc. ("ISO-NE" or the "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 the Offer Review Trigger Prices ("ORTPs") 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 2022 for the Capacity Commitment Period that begins on June 1, 2025. The ISO is requesting that the new ORTP values and associated Tariff revisions become effective on June 8, 2021. As is discussed in greater detail below, an order accepting the FCA 16 ORTP values and associated Tariff revisions by the requested effective date is necessary to ensure the ISO is able to administer FCA 16 in February 2022, without delay.

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.

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I. INTRODUCTION

In this filing, the ISO proposes to update the ORTP values that are used as part of the buyer-side mitigation process employed in the Forward Capacity Market for new capacity resources. The ISO's stakeholder advisory group, the New England Power Pool ("NEPOOL"), did not vote to support all of the ISO's proposed values, and in particular voted to support alternative values for certain technologies, including offshore wind and photovoltaic solar. These alternative NEPOOL-supported values, as well as certain other related NEPOOL-supported Tariff changes, create a "jump ball" under the Participants Agreement. Accordingly, the ISO must file the NEPOOL alternative along with the ISO's proposal, for the Commission to determine which proposal is "just and reasonable and preferable."³

In this introduction, the ISO provides an overview of its filing, and highlights its strong opposition to certain aspects of NEPOOL's alternative proposal. In Section II, the ISO requests a 62-day effective date for its proposed ORTP values and related Tariff changes, and explains why an order by this date is necessary for the ISO to maintain the FCA 16 auction schedule, without delay. Section IV addresses the standard of review that applies in a "jump ball" situation, and Section V summarizes the materials filed in support of the ISO's FCA 16 ORTP values and related Tariff changes. Then, Sections VI-VIII describe the ORTP calculation process at a high level and explain the updated values for FCA 16. Sections XI steps through the various NEPOOL alternative values and Tariff amendments, and explains the ISO's opposition to those alternatives) to the rules that apply for updating the ORTPs in the "interim" years between the years when a full review is undertaken. Section XI then reviews the robust stakeholder process regarding the ORTPs.

A. This Filing Fulfills the ISO's Tariff Obligation to Update the ORTPs for FCA 16

This filing is required by Section III.A.21.1.2 of the ISO's Tariff. Specifically, Section III.A.21.1.2(a) states that ORTPs "shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025, and no less often than once every three years thereafter." It further requires that the ISO (or more specifically, its Internal Market Monitor) review the results of the recalculation with stakeholders, and then file the recalculated values with the Commission prior to FCA 16.

ORTPs are thresholds to determine whether the ISO's Internal Market Monitor ("IMM") must review offers for new capacity in the FCM for the possible application of buyer-side market power mitigation. Specific ORTPs are established for various resource technology types, and must reflect the competitive cost of new entry (net of competitive market revenues a resource would be expected to receive, *e.g.*, for energy and ancillary services) for each specified technology. New resource capacity supply offers below the technology-specific ORTP must

³ See Participants Agreement, Section 11.1.5, *available at* https://www.iso-ne.com/static-assets/documents/2015/10/parts_agree.pdf.

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undergo IMM review. Offers at or above the ORTP can proceed to the auction without IMM review.⁴

As discussed in detail in this transmittal letter, as well as in supporting materials filed herewith, to comply with the Tariff the ISO is updating the ORTP values for a range of technologies that have traditionally participated in the FCM, including simple cycle and combined cycle gas turbines, onshore wind, and various categories of demand response. Some of these categories, including in particular onshore wind, have experienced a significant decrease in their costs since the last time ISO-NE updated ORTP values, and this is reflected in the resulting ORTP values for FCA 16.

In addition, the ISO is, for the first time, proposing ORTP values for two new technologies—photovoltaic solar generation, and battery-based electric storage (specifically, lithium ion battery storage). As the development costs for these technologies have decreased, the region has experienced a significant increase in the number of photovoltaic solar and battery storage facilities expressing an interest in participating in the FCM. For the first time, photovoltaic solar and battery storage facilities are expected to submit competitive offers below the Forward Capacity Auction Starting Price. Once a technology type meets that threshold, ISO-NE is required to calculate an ORTP value for it.⁵

Finally, the ISO evaluated, but ultimately did not calculate an ORTP value for, the offshore wind generation technology. After performing a thorough, "bottom-up" engineering-based cost analysis of the competitive cost of entry for large-scale offshore wind development in New England, the ISO determined that the competitive cost is still above the Forward Capacity Auction Starting Price. Therefore, in accordance with the Tariff, ISO-NE is not proposing an ORTP value for the offshore wind technology.⁶

It is important to underscore that ISO-NE's determination that an ORTP value is not required for offshore wind generation projects in no way dictates or otherwise limits the price at which a capacity supplier with a proposed new offshore wind resource may offer its capacity into

⁴ See Tariff Section III.13.1.1.2.2.3, which states: "All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section." The ISO is not proposing any changes to this review process in this proceeding.

⁵ See Tariff Section III.A.21.1.2(a). While the Tariff does not expressly describe the specific conditions under which the ISO will calculate an ORTP for a technology, Section III.A.21.1.2(a) indicates that the ISO shall use updated data for the relevant auction-cycle to complete the ORTP update; that updated data for FCA 16 indicates that the ISO is likely to receive offers from battery storage, photovoltaic solar, and (as noted below) offshore wind, and therefore it was appropriate for the ISO to calculate ORTP values for these technologies.

⁶ The details of the ISO's analysis of the competitive cost of entry for large-scale offshore wind development are explained in the supporting testimony of Danielle S. Powers, Senior Vice President of Concentric Energy Advisors, Inc., and the Mott MacDonald, Inc. Offshore Wind ORTP Report, both of which are included as attachments to this filing.

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the Forward Capacity Auction. (This is equally true for capacity suppliers with resources of any other technology type.) The ORTP is simply an administrative threshold used by the IMM to avoid unnecessary review of offers in the Forward Capacity Auction that do not raise any potential (buyer-side) market power concerns. Thus, the ORTP is not a rate paid to, and does not factor into the calculation of any rate paid to, a capacity supplier.

The determination that the competitive cost of new entry for offshore wind is too high to warrant the specification of an ORTP in the Tariff for this technology simply means that the IMM is obligated to review all capacity supply offers from new offshore wind resources under the existing buyer-side mitigation rules (or Minimum Offer Price Rules). In other words, there is no upper threshold for review, and so all offers for new offshore wind resources must be reviewed by the IMM. Importantly, the ISO is not proposing changes to the Minimum Offer Price Rules ("MOPR") that dictate how the IMM is to perform its review of a new capacity resource offer, when that review is required.

B. NEPOOL Supported Certain Alternative ORTP Values and Related Tariff Changes

The ISO and its IMM reviewed the FCA 16 ORTP values and related Tariff changes with stakeholders over a series of meetings throughout 2020 and the first part of 2021. During the course of those meetings, a consortium of stakeholders presented alternative proposals on ORTP values for the offshore wind, photovoltaic solar, and storage technologies, as well as related Tariff changes to reflect the ORTP calculation methodology that it used to support some of its alternative ORTP values. The alternative proposals lowered the ORTP values for these three technologies. In the case of offshore wind, the proposal reduced the value dramatically, to \$0.000/kW-month. The ISO and the IMM carefully reviewed these alternative values, as well as the related Tariff changes, and made adjustments to the ISO's proposed ORTP values where appropriate. However, as discussed in more detail in Sections IX and X below, the ISO was ultimately not able to support a number of the proposed alternatives.

NEPOOL voted to support several of the stakeholder-proposed alternatives, including: the ORTP values for offshore wind, photovoltaic solar, and battery storage technologies; an alternative ORTP calculation method that employs a new "Economic Life" concept⁷; and various other alternative inputs, assumptions, and changes to the ORTP calculation method. Because NEPOOL's support of these alternatives met the applicable threshold, the ISO and NEPOOL are each submitting a proposal pursuant to the "jump ball" process set forth in Section 11.1.5 of the Participants Agreement. As further discussed in Section IV of this transmittal letter, the "jump ball" process requires the Commission to consider both proposals and to adopt any or all of the

⁷ The "New Capacity Resource Economic Life" proposal supported by NEPOOL is unrelated to the economic life concept that is employed in the IMM's review of Retirement De-List Bids, addressed in Section III.13.1.2.3.2.1.2.C of the Tariff. This latter concept was the subject of a Commission proceeding starting in 2018, which has no bearing on the proposal before the Commission in this proceeding. *See e.g., ISO New England Inc. and New England Power Pool Participants Committee*, Order Granting Rehearing, 170 FERC ¶ 61,187 (March 10, 2020).

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ISO proposal or the NEPOOL proposal "as it finds, in its discretion, to be just and reasonable and preferable."

C. The Commission Should Reject the NEPOOL-Supported ORTP Values for Offshore Wind and Solar, as well as NEPOOL's Proposed New "Economic Life" Concept for the ORTP Calculation Methodology

As fully explained in this transmittal letter and in the supporting materials included with this filing, for the large majority of the proposed revisions with respect to which the ISO and NEPOOL differ, the ISO's proposal is, in the words of the Participants Agreement, "superior."⁸

However, the ISO's decision not to support the NEPOOL alternatives does not, in all cases, reflect significant concern with the particulars of NEPOOL's proposed changes. Rather, for some changes, the methodology employed to derive the NEPOOL alternative is not sufficiently transparent, but the end result is not, in the ISO's view, outside the bounds of reasonableness. Where this is the case, the ISO has endeavored to highlight that it does not have significant concerns with the NEPOOL alternative, and thus with the Commission's acceptance of that alternative should the Commission deem the NEPOOL alternative appropriate.

In other cases, however, the ISO has fundamental and significant concerns with the alternatives proposed, and the ISO endeavors in this transmittal to provide as much detail to the Commission as it can regarding the basis for its opposition. The ISO is particularly concerned about NEPOOL's offshore wind ORTP value as well as the new "Economic Life" definition and associated modification to the ORTP calculation method.

The ISO strongly opposes the NEPOOL-supported ORTP value for offshore wind, which is significantly below the competitive cost of new entry for an offshore wind resource in New England. NEPOOL used an opaque, poorly-justified methodology for calculating the more important inputs (including, in particular, the capital costs) for its offshore wind ORTP. The methodology is not consistent with the methodology used to calculate any other ORTP value, and NEPOOL has provided no explanation for departing from the well-established method that the ISO has employed to date (and which NEPOOL otherwise uses for its other NEPOOL-supported values).

Further, the NEPOOL alternative for offshore wind is based on capital cost data largely relevant to offshore wind projects outside of New England; there are critical differences between developing offshore wind facilities in New England and developing such facilities in other parts of the world, and even other parts of the United States. The NEPOOL alternative ignores these differences in order to produce a value that substantially understates the development costs for an offshore wind project in New England.

⁸ See Participants Agreement, Section 11.1.15, explaining in relevant part that "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."

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Finally, the NEPOOL offshore wind ORTP relies upon NEPOOL's ill-supported new "Economic Life" concept, which calls for extending the time horizon over which the financial model's discounted cash flow analysis is performed to calculate the ORTP. This obscures several poorly-supported or wholly unfounded assumptions that, when applied to the ORTP calculation, artificially lower the ORTP value dramatically.

For all of these reasons the ISO does not support—and strongly opposes—NEPOOL's proposed offshore wind ORTP value and the new "Economic Life" concept. The ISO also has similar concerns with NEPOOL's ORTP value for photovoltaic solar, given its reliance on the new "Economic Life" concept, and has separate concerns with several of the other NEPOOL-supported alternatives. The ISO explains and provides its position on each of the NEPOOL-supported alternatives in Sections IX and X of this transmittal letter.

D. This Proceeding Is Not a Referendum on the MOPR

To be clear, the choice between the ISO's evaluation of the competitive cost of new entry for offshore wind—which follows the same sound approach that is utilized for calculating ORTPs for all other technologies—and NEPOOL's proposed alternative—which follows an entirely different, unsound approach—is not an academic matter. While the ORTPs are administrative thresholds and do not establish a rate paid to capacity suppliers, they play an important role in supporting the competitiveness of the Forward Capacity Auction. By serving as the threshold for IMM review, the ORTPs determine which offers for new supply the IMM will review under the MOPR. Theoretically, then, setting an ORTP *too low* would permit resources that *ought* to be reviewed under the MOPR to avoid undergoing that review.

Setting an artificially-determined ORTP at *zero*—as NEPOOL proposes for both offshore wind and photovoltaic solar—is functionally equivalent to having no MOPR at all (for such technologies), regardless of their true costs of entry. At an ORTP of zero, no new capacity supply offer would be reviewed by the IMM at all, even if its costs are understated such that its unmitigated entry would suppress prices for other resources. And, as offshore wind and solar are expected to dominate the new entry in New England, setting their ORTPs to zero would eviscerate the MOPR.

Many New England states and stakeholders are interested in the elimination of the MOPR, and the ISO has, in recent comments filed with the Commission, recognized that New England must address concerns about the FCM's failure to account for the capacity provided by sponsored resources that do not clear the market as a result of the MOPR.⁹ To be clear, ISO-NE intends to work with the states and stakeholders to achieve the elimination of the MOPR in a manner that maintains reliability.

We understand the urgency felt by some stakeholders regarding the elimination of the MOPR. Nonetheless, we ask the Commission to provide the region with the time needed to

⁹ See ISO New England Inc., Pre-Conference Statement, Docket No. AD21-10-000 (filed March 19, 2021).

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address such significant market changes, and not to uphold arguments that would seek to indirectly eliminate the MOPR through the adoption of inaccurate ORTPs.

II. REQUESTED EFFECTIVE DATE

The ORTPs in this filing are part of various Forward Capacity Market parameters that are being updated in advance of FCA 16. The ISO separately filed an updated Dynamic De-List Bid Threshold in December 2020.¹⁰ The ISO also filed Cost of New Entry ("CONE"), Net CONE, and Capacity Performance Payment Rate ("PPR") values in December 2020,¹¹ and submitted updated CONE, Net CONE and PPR values on March 30, 2021 in response to a Commission deficiency notice issued in that proceeding.¹² The instant filing has been delayed beyond the filing date of the other parameters given the need to account for changes in federal tax law that were enacted in December 2020. The impact of the changes to the tax laws are discussed in Sections IX and X below, as well as in the Powers Testimony and the CEA ORTP Addendum.

The ISO respectfully requests that the Commission accept the FCA 16 ORTP values and related Tariff revisions as filed herein, without suspension or hearing, to be effective on June 8, 2021, which is more than 60 days from the date of this filing. An order on or before June 8, 2021 accepting the FCA 16 ORTP values and related Tariff changes is necessary to ensure that the ISO and the region can conduct the FCA 16 qualification process without delay, and will avoid the potential for a delay in the administration of the auction in February 2022.

As the ISO has explained to the Commission in the Revised FCA 16 CONE Values Filing, the FCA 16 qualification process is already underway. The Existing Capacity Retirement window closed on March 12, 2021, and the "show of interest" window for Market Participants seeking to qualify new capacity resources for FCA 16 will close on April 23, 2021.

Two upcoming critical FCA 16 deadlines are scheduled for June 2021: the Static De-List Bid, Export Bid, and Administrative Export De-List Bid submission window (June 4-10, 2021) and the New Capacity Qualification Package submission window (June 10-18, 2021).¹³ The FCA 16 ORTP values are necessary inputs into the determination of suppliers' New Capacity Qualification Package submissions, as the ORTPs are necessary for suppliers to determine whether they must provide supporting information with their submissions to permit a review of new resource supply offers that are below the relevant ORTP.

¹⁰ See ISO New England Inc. and New England Power Pool, Market Rule 1 Change to Implement New Methodology for Calculating Forward Capacity Market Dynamic De-List Bid Threshold, Docket No. ER21-782-000 (filed December 30, 2020); Order Accepting Tariff Revisions, 174 FERC ¶ 61,162 (March 1, 2021).

¹¹ See ISO New England Inc., Updates to CONE, Net CONE, and Capacity Performance Payment Rate, Docket No. ER21-787-000 (filed December 30, 2020). ("Initial FCA 16 CONE Values Filing").

¹² See ISO New England Inc., Response to Commission Deficiency Notice and Revised CONE, Net CONE, and Capacity Performance Payment Rate Values, Docket No. ER21-787-000 (filed March 30, 2021) ("Revised FCA 16 CONE Values Filing").

¹³ See the FCA 16 Schedule, *available at* https://www.iso-ne.com/static-assets/documents/2019/02/fca-16-market-timeline-2-13-2019.pdf.

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After these deadlines, the ISO begins its time-intensive process to review and establish the amount of capacity that new resources may seek to qualify for the auction, and the IMM must separately complete its market power mitigation review for new and existing resources. Without finalized ORTP values, suppliers will not have certainty that their submitted New Capacity Qualification Packages are complete, and neither the ISO nor the IMM can complete the necessary reviews. Any such delay would risk the ISO's ability to timely complete these processes and the necessary FERC pre-auction review before the scheduled February 2022 auction. Thus, not receiving an order within 60 days would jeopardize the ISO's ability to carry out FCA 16 on time.

Importantly, rescheduling the auction would have impacts beyond FCA 16, because the outcomes of FCA 16 are necessary for Market Participants to make elections and take actions in the qualification process for FCA 17.¹⁴ Moreover, some Market Participants' project development schedules and timelines may be dependent on obtaining a Capacity Supply Obligation on the current schedule for FCA 16 (*i.e.*, in the auction scheduled to be conducted in February 2022). Finally, if the ISO cannot conduct FCA 16 as scheduled, the ISO will also need to adjust the timing of reconfiguration auctions.¹⁵ Of particular concern, the results of FCA 16 are inputs into the qualification determinations for the third annual reconfiguration auction to be conducted for the 2022-2023 Capacity Commitment Period, which is scheduled to be held in March 2022, approximately one month following the scheduled date for FCA 16.¹⁶

In sum, an order on or before June 8, 2021 on the proposed FCA 16 ORTP values and associated Tariff changes will allow the FCA 16 qualification process to proceed without further delay, avoid the need to delay the auction itself, and thereby prevent the cascading impacts to other FCM processes and future auctions.

¹⁴ The results of the immediately preceding FCA are an input into the subsequent FCA qualification process, and the qualification activities of the subsequent FCA start in proximity to the completion of the immediately preceding FCA. For example, FCA 16 is scheduled to start on February 7, 2022, and the ISO is scheduled to inform Market Participants with Existing Capacity Resources of their initially calculated FCA 17 Existing Capacity Qualified Capacity values on February 17, 2021. Between February 7, 2022, and February 17, 2022, the ISO must conclude FCA 16, finalize the results of FCA 16, and calculate, review and release the initial FCA 17 Existing Capacity Resource Qualified Capacity values. Delaying the release of the Existing Capacity Resource Qualification Capacity values would impact other FCA 17 qualification activities where this information is an important input, such as the opening of the Retirement De-List Bid and Permanent De-List Bid window.

¹⁵ Each calendar year, the ISO conducts one FCA, three annual reconfiguration auctions, and twelve monthly reconfiguration auctions and bilateral periods that cover five different Capacity Commitment Periods. For each calendar year, the FCA is held in February (*see* Sections III.13.1.10 (f) and III.13.2.1 of the Tariff), the first annual reconfiguration auction is held during the following June, the second annual reconfiguration auction is held during the following August, and the third annual reconfiguration auction is held during the following March (*see* Section III.13.4.5.1 of the Tariff).

¹⁶ FCA 16 is currently scheduled to start on February 7, 2022, and the third annual reconfiguration auction for the 2022-2023 Capacity Commitment Period will take place in March 2022 pursuant to the Tariff. The 2022-2023 Capacity Commitment Period starts on June 1, 2022.

III. DESCRIPTION OF THE ISO; COMMUNICATIONS

ISO-NE 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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*Persons designated for service.¹⁷

IV. STANDARD OF REVIEW

The ISO-NE proposed Tariff changes included herein are submitted pursuant to the ISO's rights under Section 205, which "gives a utility the right to file rates and terms for services rendered with its assets."¹⁸ In addition, Section 11.1.5 of the Participants Agreement (referred to as the "jump ball provision") requires that the ISO, as part of a Section 205 filing, present to the Commission any alternative Market Rule proposal that is approved by a Participant Vote of at least 60 percent.¹⁹ That filing must include detail sufficient to permit reasonable review by the Commission, explain the ISO's reasons for not adopting the alternative proposal, and provide an explanation as to why the ISO believes its own proposal is superior.²⁰

¹⁷ Due to the joint nature of this filing, the Filing Parties respectfully request a waiver of Section 385.203(b)(3) of the Commission's regulations to allow the inclusion of more than two persons on the service list in this proceeding.

¹⁸ Atlantic City Elec. Co. v. FERC, 295 F. 3d 1, 9 (D.C. Cir. 2002) ("Atlantic City").

¹⁹ See Participants Agreement, Section 11.1.5, *available at* https://www.iso-ne.com/static-assets/documents/2015/10/parts_agree.pdf.

²⁰ Id.

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Under Section 205, the Commission "plays 'an essentially passive and reactive role"²¹ whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable."²² 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."²³ The changes proposed herein "need not be the only reasonable methodology, or even the most accurate."²⁴ 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.²⁵

As discussed in the joint cover letter submitted by the ISO and NEPOOL, where NEPOOL has supported an alternative to the ISO's proposed FCA 16 ORTP values and related Tariff changes, the Commission may choose to "adopt any or all of ISO's Market Rule proposal or the alternate Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable." The Commission cannot, under this Section 205 filing, adopt another proposal not supported by either the ISO or NEPOOL.

V. SUMMARY OF MATERIALS FILED IN SUPPORT OF THE FCA 16 ORTP VALUES AND RELATED TARIFF CHANGES

The ISO retained the energy consultancy firm Concentric Energy Advisors, Inc. ("CEA" or "Concentric") to perform the detailed analysis for the updated ORTPs (as well as for the CONE and Net CONE values, filed separately). CEA partnered with the engineering firm Mott MacDonald, Inc. ("Mott MacDonald") for purposes of developing the detailed, bottom-up engineering estimates of project costs for each of the evaluated technology types. 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 Attachment I-1b to this filing and establishes the substantive basis for the updated FCA 16 ORTP values filed here.²⁶

²¹ Atlantic City at 10 (quoting City of Winnfield v. FERC, 744 F.2d 871, 876 (D.C. Cir. 1984)).

²² *Id.* at 9.

²³ City of Bethany v. FERC, 727 F.2d 1131, 1136 (D.C. Cir. 1984) ("Bethany").

²⁴ Oxy USA, Inc. v. FERC, 64 F.3d 679, 692 (D.C. Cir. 1995).

²⁵ *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*)).

²⁶ As indicated in its title, the CEA Report also includes detailed information (notably in Sections 3 through 6) regarding the calculation of updated CONE and Net CONE values, which, as discussed in Section V, were filed separately in December 2020, and updated in March 2021.

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As noted above, in March, the Commission issued a deficiency notice on the Initial FCA 16 CONE Values Filing, which ultimately prompted the ISO to file updated CONE, Net CONE and PPR values in Docket No. ER21-787-000 as part of its response to the deficiency notice.²⁷ The ISO's Updated CONE, Net CONE and PPR values were supported by an addendum to the CEA Report.²⁸ Because the PPR value is an input into the ORTP calculations, the ISO is also including the CEA CONE Addendum as Attachment I-1c to the instant filing.

Furthermore, as explained above, while all of the FCA 16 parameters—including the ORTPs, CONE, Net CONE and the PPR—were developed as a single project, and reviewed with stakeholders as a combined set of FCM parameters—ISO-NE is filing the ORTP values separately. This decision is a result of several factors, including of relevance here the need to recalculate several ORTP values to account for the extension of the Investment Tax Credit ("ITC") for certain renewable resource technologies. The ITC extension was enacted in late December of 2020 as the ISO was preparing to file the ORTP values. The subsequent update to the ORTPs to account for the ITC extension is explained further below in this transmittal letter, and in greater detail in the CEA ORTP Addendum that is included as Attachment I-1d to this filing.²⁹

Finally, in support of ISO-NE's ORTP evaluation for the offshore wind technology, as well as ISO-NE's critique of the NEPOOL-supported alternative offshore wind ORTP, photovoltaic solar ORTP, and the new "Economic Life" definition, the ISO is submitting with this filing the supporting testimony of Danielle Powers, Senior Vice President with Concentric (the "Powers Testimony") and the Mott MacDonald Offshore Wind ORTP Report (the "Mott MacDonald Report"). The Powers Testimony is Attachment I-1e to this filing, and the Mott MacDonald Report is Attachment I-1f.

VI. THE FUNCTION AND PURPOSE OF OFFER REVIEW TRIGGER PRICES IN THE FORWARD CAPACITY MARKET

To protect against the price-suppressing effects of new resource offers that are below a competitive level, the FCM design includes a buyer-side market power mitigation mechanism. This requires the IMM to review any new capacity resource offer at or below a screening

²⁷ See Revised FCA 16 CONE Values Filing.

²⁸ See ISO-NE Net CONE and ORTP Analysis: An Evaluation of the Net Cost of New Entry Parameter to be Used In the Forward Capacity Auction FCA-16 and Forward – Addendum – CONE/Net CONE (March 2021) (referred to herein as the "CEA CONE Addendum"), included as Attachment I-1c to this filing.

²⁹ See ISO-NE Net CONE and ORTP Analysis: An Evaluation of the Net Cost of New Entry Parameter to be Used In the Forward Capacity Auction FCA-16 and Forward – Addendum – ORTP (April 2021) ("CEA ORTP Addendum"), included as Attachment I-1d to this filing.

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benchmark known as the ORTP.³⁰ ORTPs are applicable only to new resources entering the FCM, not to existing resources.³¹

The rules concerning the IMM's review of capacity supply offers for new resources are specified in Market Rule 1, Appendix A, Section III.A.21. The ORTP serves as a proxy for the price at which a given resource technology would offer into the FCA were it not to receive "out-of-market" revenue as defined in Market Rule 1.³² The ORTP for a technology type is not an offer price that a capacity supplier is held to in the Forward Capacity Auction. Rather, it is simply a *screen* to determine which resource offers require additional scrutiny from the IMM to assess whether those offers are uncompetitively low—indicative of out-of-market revenue. Offers at or above the relevant trigger price value are assumed to be competitively priced, and may participate in the FCA at or above that price value without further review.³³ Offers below the relevant ORTP are subject to additional IMM review through the process specified in Section III.A.21.

ORTPs are calculated for specific resource types every three years and adjusted (*i.e.*, indexed) annually.³⁴ The method for calculating each ORTP is set forth in Section III.A.21.1.2; the calculation estimates the net cost of entry for each resource technology that may participate in the FCM, subject to certain criteria (discussed further below).³⁵ Importantly, ORTPs are intended to represent the low end of the range of potential competitive offers, to prevent new resources from offering at prices significantly below their true net cost of entry. Establishing the ORTPs at the low end of the spectrum of competitive entry costs strikes a reasonable balance by not subjecting offers that are "clearly competitive" to IMM evaluation; the IMM reviews only

³⁰ See Tariff Section III.A.21.1 ("For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.").

³¹ *Existing* capacity resources are subject to supplier-side market power mitigation rules.

³² See Tariff Section III.A.21.2(b)(i) ("The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose.").

³³ See Tariff Section III.A.21.1 ("Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor.").

³⁴ See Tariff Section III.A.21.1.2(a) ("The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter.").

³⁵ The use of resource-specific benchmarks was mandated by the Commission in an order issued on April 13, 2011 in Docket No. ER10-787-000, *ISO New England Inc. and New England Power Pool Participants Committee, Order on Paper Hearing and Order on Rehearing*, 135 FERC ¶ 61,029 (2011) (the "April 13, 2011 Order").

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those capacity supply offers "that plainly appear commercially implausible absent out-of-market revenues."³⁶

For those resource types for which it is not possible to establish a reliable ORTP value, a default ORTP is set equal to the Forward Capacity Auction Starting Price.³⁷ This means that the IMM will automatically review offers for these resource types in order "to protect against the exercise of buyer-side market power that could inappropriately suppress capacity prices."³⁸ A resource type for which an ORTP cannot be reliably calculated is likely to be based on an emerging technology, or one where each installation is unique, about which there is insufficient cost data.

It is important to underscore that having offers subject to review by the IMM does not prevent any resource from offering its capacity into the FCM at a price that reflects its true new entry costs, that is, its cost in the absence of any offsetting "out-of-market" revenue. Any new resource that wants to offer at a price that is below the applicable ORTP for its technology can request a resource-specific offer floor price applicable to its participation in the FCM.³⁹

The availability of the offer floor price mechanism underscores an important point relative to the development of the ORTPs. The offer floor price mechanism affords a supplier complete flexibility to demonstrate that its proposed offer does not reflect out-of-market revenue. A supplier that is able to do so is free to take whatever economic risk it chooses in its participation in the Forward Capacity Auction. Nothing about the establishment of the ORTP impedes this ability for the supplier (or in any way impacts the supplier's use of the offer floor price mechanism). *In contrast*, establishing an ORTP that is too low—meaning that it does not reflect all the costs a *competitive* supplier would incur to construct a resource of a particular technology—subverts the purpose of the MOPR. This is because an artificially low ORTP permits a supplier to offer at prices that reflect out-of-market revenue, the very thing that the MOPR is intended to prevent.⁴⁰ Therefore, while there is <u>no</u> economic risk to the supplier who

³⁶ See ISO New England Inc., Order on Compliance Filing, 142 FERC ¶ 61,107 (February 12, 2013) (the "February 12, 2013 Order") at P 38.

³⁷ See Tariff Section III.A.21.1.1, the exception being the default ORTP for New Import Capacity Resources, which is set equal to the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

³⁸ See April 13, 2011 Order at P 166 ("if the offer floor is set at a level that approximates the net cost of entry of a new resource, offer-floor mitigation would deter the exercise of buyer-side market power and the resulting suppression of capacity market prices associated with uneconomic entry. By preventing new resources from offering at prices that are significantly below their true net cost of entry, new resources would not be able to lower the price of capacity significantly below competitive levels.") (internal citations omitted).

³⁹ See February 12, 2013 Order at P 39, in which the Commission addressed challenges to certain assumptions reflected in the ORTPs by stating that if a resource developer "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." See also ISO New England Inc., Order on Proposed Tariff Revisions, 146 FERC ¶ 61,084 (February 11, 2014) (the "February 11, 2014 Order") at P 3 ("offers below the relevant ORTP may be accepted into the FCA, but must first be justified to the Internal Market Monitor (IMM) during a unit-specific review process.").

⁴⁰ See April 13, 2011 Order at P 14 ("Allowing [out-of-market] capacity to clear creates a significant design issue for the FCM; all other things being equal, it suppresses the clearing price below competitive levels."). See also N.J. Bd. of Pub Utils. v. FERC, 744 F.3d 74, 97 (3d Cir. 2014) (Explaining, in the context of the PJM market, that the

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can demonstrate that its competitive costs are below the ORTP, the entire marketplace suffers if the ORTP is set artificially low.

VII. OVERVIEW OF THE ORTP CALCULATIONS

The CEA Report and the CEA ORTP Addendum explain in considerable detail the ISO's development of the ORTPs for each technology. Sections 7 and 8 of the CEA Report, along with the CEA ORTP Addendum, provides a full description of the ORTP calculation process and the resulting benchmark net entry cost values for each technology for which an ORTP is being proposed. Provided here is an overview of the ORTP calculation process, highlighting certain important aspects that are particularly relevant to the FCA 16 ORTP results.

The ORTP review process begins with the application of screening criteria to identify the resource types for which ORTPs will be calculated. The screening process considers whether a technology has previously been installed in the New England region and participated in recent auctions, whether reliable cost information is available to calculate an ORTP, and whether a resource's first-year revenue requirement would be below the expected Forward Capacity Auction Starting Price.⁴¹

If a resource technology meets the screening criteria, the ORTP is calculated by estimating the gross entry costs and expected net market revenue, based on assumptions about the technology's operating characteristics, energy and ancillary service market participation, and so forth. Specifically, Section III.A.21.1.2 requires the following calculation:

Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).⁴²

The process of calculating the ORTP values is similar to the process used to calculate the new CONE and Net CONE values. However, the process differs in several important aspects, reflecting the purpose for the ORTPs as used in the MOPR. Of particular note, ORTPs are to serve as a screen for non-competitive offers for the prompt auction—in this case FCA 16—and therefore are based on market conditions that are expected to prevail in the upcoming auction. In

purpose of the buyer-side mitigation rules are to "ensure[] that [a] new resource is economical—*i.e.*, that it is needed by the market—and ensure[] that its sponsor cannot exercise market power by introducing a new resource into the auction at a price that does not reflect its costs and that has the effect of lowering the auction clearing price.").

⁴¹ Section 7.C of the CEA Report discusses the application of the screening criteria.

⁴² See Tariff Section III.A.21.1.2(b) and (c).

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contrast, Net CONE is modeled under long-run market equilibrium conditions. As a result, for the ORTP calculations, the historical Locational Marginal Prices are used in the dispatch models, with no adjustments to those prices to reflect long-run equilibrium conditions (as is performed for the determination of CONE and Net CONE).⁴³

Similarly, revenue projections for scarcity conditions for ORTPs are based on expected scarcity hours under expected near-term market conditions in the New England region (which has excess supply presently), rather than expected scarcity hours under long-run equilibrium conditions. This affects both resources' estimated energy and reserve revenue during real-time reserve shortages (which are incorporated in the discounted cash flow analysis as a separate line item outside of the ORTP dispatch models), and Capacity Performance Payment revenue (also incorporated in the discounted cash flow analysis as a separate line item). Both of those scarcity-based revenue estimates assume 7.4 expected annual capacity scarcity condition hours, based on market conditions expected to prevail for the FCA 16 auction period.⁴⁴ This means that scarcity revenue and Capacity Performance Payment revenue projections reflect a lower level of expected scarcity hours (reflecting market conditions expected in FCA 16) than conditions expected at the Installed Capacity Requirement (*i.e.*, for a market in long-run equilibrium).

As explained above, and consistent with past practice, the ORTP values reflect the low end of the competitive range of expected offers so that an individual offer review is performed only for offers that do not appear to be commercially plausible absent out-of-market revenue.⁴⁵ This approach means that certain financial assumptions used in the ORTP calculations are more favorable (that is, result in lower net entry costs) than the assumptions used for CONE/Net CONE purposes. Of particular note:

- Lower-end return on equity and cost of debt assumptions are employed, relative to those used for the CONE calculation, to reflect the low end of the competitive range and to account for the lower risk associated with contract-backed energy revenues that is required under Section III.A.21.1.1 for the ORTP calculation. This produces a lower-end cost of capital for the ORTP calculations;
- A more conservative capital structure is also assumed in favor of more leverage and lower returns to equity, also consistent with the low end of the competitive range of offers; and
- Finally, it is assumed that at least some new resources will be able to monetize the full value of the increased first-year bonus depreciation allowance that was

⁴³ CEA Report at 61-63 (explaining the level of excess, or LOE, adjustments for calculation of Net CONE), and at 86 (explaining that, for ORTP purposes, "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.").

⁴⁴ CEA Report at 86-87.

⁴⁵ The Commission recognized this practice in the February 12, 2013 Order at P 39, stating: "use of trigger prices at the low end of the spectrum strikes a reasonable balance by not subjecting clearly competitive offers to IMM evaluation, but only addressing those offers that plainly appear commercially implausible absent out-of-market revenues."

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increased to 100% under the Tax Cuts and Jobs Act enacted at the end of 2018, and therefore this treatment is reflected in the ORTP calculations.

These financial assumptions are addressed in greater detail in Section 7.D of the CEA Report.

Finally, on December 27, 2020, the Consolidated Appropriations Act was signed into law (referred to herein as the "2021 Appropriations Act"), which included material changes to federal Investment Tax Credit ("ITC") provisions for certain renewable technologies. Concentric provides their assessment of the impact of the recent federal legislation on the specific ISO-proposed FCA 16 ORTPs in the CEA ORTP Addendum. The analysis shows the ITC provisions led to revised cost input estimates for the photovoltaic solar technology and both onshore and offshore wind technologies; however, the ITC changed the final ORTP value for only the photovoltaic solar technology.

VIII. ISO'S PROPOSED OFFER REVIEW TRIGGER PRICES FOR FCA 16

Applying the screening criteria, the ISO considered possible ORTPs for the following technologies: Combined Cycle, Combustion Turbine, Onshore Wind, Offshore Wind, Energy Efficiency, On-Peak Solar, Demand Response (Load Management and Distributed Generation), Co-located solar/battery, Photovoltaic Solar, and Stand-Alone Battery Storage. The application of the criteria is discussed in Section 7.C of the CEA Report.

The ISO determined the offshore wind technology would have estimated costs that are above the Forward Capacity Auction Starting Price for FCA 16.⁴⁶ Therefore, as explained above, no ORTP was calculated for offshore wind.

After lengthy discussions with stakeholders, the ISO agreed that it would not propose a separate, "bottom-up" ORTP calculation for emerging co-located solar/battery storage (so called "hybrid resource") technologies. Instead, the ORTP applicable to co-located resources would remain subject to the existing ORTP calculation rules for co-located facilities. Those rules require the use of the weighted average formula in Section III.A.21.2(c) of the ISO Tariff.

Table 1 below lists the ISO-calculated ORTP values for FCA 16, as well as the NEPOOL-supported alternative ORTP values.

⁴⁶ See the Powers Testimony at 2-33 and Section IX.B below for a discussion of the offshore technology calculation.

Generating Capacity Resources			
Technology Type	Offer Review Trigger Price (\$/kW-month)		
	ISO-NE	NEPOOL	
Simple Cycle Combustion Turbine	\$5.355	\$5.355	
Combined Cycle Gas Turbine	\$9.811	\$9.811	
On-Shore Wind	\$0.000	\$0.000	
Offshore Wind	N/A	\$0.000	
Energy Storage Device – Lithium Ion Battery	\$2.912	\$2.601	
Photovoltaic Solar	\$1.381	\$0.000	

Table 1: Comparison of ISO-NE and NEPOOL ORTP Values

Demand Capacity Resources			
Technology Type	Offer Review Trigger Price (\$/kW-month)		
	ISO-NE	NEPOOL	
Load Management (Commercial / Industrial)	\$0.750	\$0.750	
Previously Installed Distributed Generation	\$0.750	\$0.750	
New Distributed Generation	Based on generation technology type	Based on generation technology type	
On-Peak Solar	\$5.414	\$5.414	
Energy Efficiency	\$0.000	\$0.000	

Other Resources			
	ISO-NE	NEPOOL	
All other technology types	Forward Capacity Auction Starting Price	Forward Capacity Auction Starting Price	

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For context, we have summarized below the types of projects that are generally included in each of the above-specified ORTP categories.

Generating Capacity Resources:

- Simple Cycle Combustion and Combined Cycle Gas Turbines Projects assigned to these ORTP categories include conventional thermal combustion-turbine and combined-cycle power plants, fueled by natural gas or with dual-fuel (oil and natural gas) capability.
- On-Shore Wind Projects assigned to this ORTP category include land-based wind turbine facilities.
- *Offshore Wind* Projects assigned to this ORTP category include wind turbine facilities located in the waters of the Atlantic Ocean off the New England coast.
- *Energy Storage Device* Energy storage device facilities can be stand-alone, or colocated with a generating resource (e.g. photovoltaic solar). The co-located facilities tend to be smaller in size relative to the stand-alone facilities.
- *Photovoltaic Solar* Photovoltaic solar facilities can be stand-alone or co-located with energy storage devices.

Demand Capacity Resources:

- *Commercial and Industrial Load Management* Projects assigned to this ORTP category include measures installed by small commercial customers who can control their sitespecific electricity demand through direct load management
- Energy Efficiency (includes both Commercial and Industrial Energy Efficiency and Residential Energy Efficiency) Projects assigned to this ORTP category 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 consumed at its facility while delivering a comparable or improved level of end-use service (*e.g.*, energy efficient lighting, motors, refrigeration, heating and air conditioning).
- *Previously Installed Distributed Generation* Projects assigned to this ORTP category include previously installed behind-the-meter distributed generation that was installed more than five years before the start of the Capacity Commitment Period.
- *On-Peak Solar* Projects assigned to this ORTP category include behind-the-meter photovoltaic solar distributed resources that are active load reductions. (Note that, in contrast, front-of-the-meter photovoltaic solar generators are considered Generating Capacity Resources, in that category above.)

In Table 2 below, we report the percentages of new capacity resources that qualified for and participated in recent forward capacity auctions for each category.⁴⁷ Please note that the percentages provided are approximations, as the FCA 14 and 15 ORTP categories in the ISO's databases for those auctions do not match exactly the categories that are included in this filing of the FCA 16 ORTP values. Of particular note, the far-right column shows that for FCA 15, the

⁴⁷ The percentages shown reflect participation in the FCA and not the amount that cleared the applicable FCA, for each category.

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substantial majority of all new generating capacity resources participating in the auction were either energy storage technologies (16%) or solar technologies (45%).

1.0					
Resource Type	Technology	FCA 14 Share of FCA QC*	FCA 14 Share of Number of Resources*	FCA 15 Share of FCA QC*	FCA 15 Share of Number of Resources*
Demand	Load Management	7%	10%	4%	10%
Demand	Energy Efficiency	11%	4%	4%	5%
Demand	Various**	7%	9%	8%	18%
Generator	Combined Cycle Gas Turbine	23%	<1%	19%	1%
Generator	Combustion Turbine Generator	15%	1%	11%	1%
Generator	On-Shore Wind	<1%	<1%	<1%	1%
Generator	Offshore Wind	3%	<1%	3%	1%
Generator	Electricity used for Energy Storage ***	25%	5%	49%	16%
Generator	Solar ***	8%	69%	3%	45%
Generator	Other	<1%	1%	1%	2%

 Table 2: Generating and Demand Capacity Resources that Participated as

 New Capacity Resources in FCA 14 and FCA 15. By Technology Type

*Listed values rounded to the nearest percent.

**Includes contributions from Demand Capacity Resources with technology types that are not explicitly covered by a defined ORTP category (*e.g.*, on-peak solar and new behind the meter intermittent distributed generation), or Demand Capacity Resources with mixed technology types.

***May include contributions from co-located solar and energy storage facilities represented by a single Generating Capacity Resource.

IX. ORTP VALUES AND ORTP CALCULATION REVISIONS THAT ARE SUBJECT TO NEPOOL ALTERNATIVE PROPOSALS

While the ORTP calculations for the large majority of technologies were non-controversial, stakeholders voted on the ORTP values as a package, and ultimately voted not to support the ISO-proposed ORTP values. Instead, NEPOOL supported a package of alternatives that included different ORTP values for three technologies—energy storage devices, photovoltaic solar, and offshore wind. In addition, NEPOOL supported an alternative that would require the ISO to calculate ORTPs for each technology using a new, technology-specific "Economic Life" definition and assumptions for each ORTP. NEPOOL used this alternative in its calculation of alternative ORTP values for photovoltaic solar and offshore wind technologies, but did not incorporate that alternative into any other ORTP values. The Honorable Kimberly D. Bose April 7, 2021 Page 22 of 58

In this section, we review the ORTP values—both the ISO-calculated value and the NEPOOL alternative—for offshore wind, photovoltaic solar, and energy storage devices—explaining both the ISO's rationale for its proposed value and its position with respect to the NEPOOL alternative. We also discuss the NEPOOL-supported alternative on the calculation of ORTPs for co-located facilities. First, however, this section begins with the NEPOOL-supported "Economic Life" alternative, given its application to the NEPOOL-supported ORTPs for both the photovoltaic solar and the offshore wind technologies discussed subsequently.

A. NEPOOL Proposal to Define and Employ an "Economic Life" Variable in the ORTP Calculation Method for Generating Capacity Resources

1. The Current Tariff Requires the Use of a 20-Year Financial Horizon for Calculating ORTPs

An important component of the discounted cash flow methodology that is used for calculating the technology-specific ORTPs is the time horizon over which the financial calculation is performed. In simplest terms, the financial model's time horizon represents the number of years over which the cash flows are analyzed to determine the capacity revenue that a resource needs to break even. There is no one-size-fits-all "magic number" for the time horizon to be used; rather, the horizon incorporates assumptions about the duration of a number of different income and expense streams over time (*e.g.*, the duration of debt repayment periods, energy revenue streams, and so forth).

In particular, there are several key time horizon assumptions that are generally incorporated into the financial model, and therefore impact the ORTP values. Specifically, as Ms. Powers explains in her supporting testimony, the financial modeling of a new generating facility generally comprises three time horizons: i) the assumed debt amortization horizon; ii) the facility's expected physical life, and (iii) the facility's expected operating life.⁴⁸ Ms. Powers explains, "Each of these must be accounted for in establishing the financial horizon that is appropriate for performing the [discounted cash flow] analysis."⁴⁹

- The debt amortization horizon, or "debt term" for short, represents the number of years over which the debt incurred to develop the project is to be fully repaid to lenders.⁵⁰
- A facility's expected physical life represents how long the facility is expected to function under prudent operating and maintenance practices.⁵¹

⁴⁸ Powers Testimony at 9.

⁴⁹ *Id.* at 9-10

⁵⁰ *Id.* at 10.

⁵¹ *Id.* at 14.

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• A generating facility's expected operating life is generally defined as the time period over which the facility is expected to be profitable, considering market and technological obsolescence.⁵²

For the calculation of ORTPs, the Tariff requires that the ISO assume a 20-year financial horizon for the ORTP calculation for each technology type. Specifically, Section III.A.21.1.2(b) states that "[t]he model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties)." This modeling assumption reflects the fact that, generally speaking, for significant new technologies being developed in New England under PPAs (such as offshore wind, for example), publicly-available contracts have 20-year terms.⁵³ Financing for the facility, in turn, accounts for the length of time for which the resource is expected to receive a certain stream of revenues, and therefore would rely on the timely repayment of the debt over the term of the PPA.⁵⁴

While a facility's expected operating and physical life for some technology types *might* extend beyond a 20-year PPA time horizon, this possibility is too tenuous for use in the ORTP calculations. First, any revenues beyond the period of the PPA will be highly uncertain, and may need to be offset by (equally uncertain) additional capital improvements as the resource ages.⁵⁵ In addition, with new technologies in particular, there is likely to be little commercial experience—and therefore insufficient data—demonstrating the typical physical and operating lifetimes of the technology in practice.

For these reasons, the ISO has consistently assumed a 20-year financial time horizon for purposes of calculating each technology's ORTP, in accordance with its Tariff. This approach is supported by Commission precedent, finding that "default MOPR values should maintain the same basic financial assumptions, such as the 20-year asset life, across resource types"⁵⁶ in keeping with the Commission's determination "that standardized inputs are a simplifying tool appropriate for determining default offer price floors.... [I]t 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."⁵⁷

⁵² *Id.* at 15.

⁵³ *Id.* at 10.

⁵⁴ *Id.* at 10-11.

⁵⁵ *Id.* at 14-16.

⁵⁶ See Calpine Corporation v. PJM Interconnection, L.L.C., 171 FERC ¶ 61,035 (2020) at P 290, citing Calpine Corporation v. PJM Interconnection, L.L.C., 169 FERC ¶ 61,239 (2019) at P 153.

⁵⁷ Calpine Corporation v. PJM Interconnection, L.L.C., 169 FERC ¶ 61,239 (2019) at P 153, citing PJM Interconnection, L.L.C., 143 FERC ¶ 61,090 (2013) at P 144.

2. The ISO Does Not Support the NEPOOL Alternative to Require the Use of a Technology-Specific "Economic Life" Evaluation

NEPOOL is proposing a revision to the ORTP calculation methodology to replace the requirement that the ISO calculate ORTPs using 20 years of discounted cash flows with the requirement that the calculation be performed "over the New Capacity Resource Economic Life of the project." NEPOOL defines the new term "New Capacity Resource Economic Life" as "the number of years that is the lesser of (a) the period of time that a New Capacity Resource of a given technology type or types would reasonably be expected to operate before the resource becomes unprofitable for at least two consecutive years, (b) the expected physical operating life of the resource, or (c) 35 years."⁵⁸ We refer to NEPOOL's proposal as the "Economic Life proposal."

The ISO strongly opposes the Economic Life proposal for several reasons. First, the "Economic Life" concept that the NEPOOL amendment employs is hopelessly ambiguous, leaving the ISO with no clear guidance on how to determine the manner in which each technology-specific ORTP should be calculated. Second, it hides a critical component to the financial horizon of a resource, likely leading to unreasonable financial assumptions that could artificially suppress ORTP values. Finally, NEPOOL applies its amendment selectively to just two technology types, which is a violation of the filed rate doctrine and is unduly discriminatory. We will address each of these objections in detail below.

The Economic Life proposal fails to provide necessary guidance for how to calculate the "life" of each technology, which is likely to create significant issues when it comes to calculating ORTPs for new or emerging technologies, in particular. While the definition of the New Capacity Resource Economic Life term refers to the lesser of the "operating life" and the "physical life" of the technology, the proposal ignores the fact that little, if any, data is available for determining with any degree of certainty the likely operating or physical life of new technologies such as offshore wind and large-scale photovoltaic solar. These technologies are sufficiently new that, to our knowledge, there are no commercial data demonstrating how long they typically operate prior to retirement.⁵⁹ Lacking clear guidance, it is highly likely that any proposed calculation will engender significant, fact-intensive litigation over the "correct" operating life or physical life to use for any given technology type. This runs counter to the Commission's precedent, as noted above, that "default MOPR values should maintain the same basic financial assumptions, such as the 20-year asset life, across resource types,"⁶⁰ so that "resource offers are evaluated on a comparable basis."⁶¹

⁵⁸ See NEPOOL Tariff Redlines, included as Attachments N-1i and N-1j to this filing.

⁵⁹ See Powers Testimony at 14-15 (discussing the lack of data on the physical lives of offshore wind facilities given that facilities in the U.S. and internationally are still mostly in their operational infancy).

⁶⁰ Calpine Corporation v. PJM Interconnection, L.L.C., 169 FERC ¶ 61,239 (2019) at P 153.

⁶¹ *Id.* One *could* argue that by using "Economic Life" assumptions that more accurately reflect the actual operating life or physical life of a resource, the ORTPs would provide more accurate comparability across resource types. While this might be sound in concept, it is not so with respect to the NEPOOL "Economic Life" amendment for two reasons. First, as explained above, the inherent ambiguities in NEPOOL's "Economic Life" concept render it

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NEPOOL's Economic Life proposal also fails to account for a critical component of the financial horizon for a given technology—its debt term, or debt horizon. As explained above, the financial horizon of a generating facility must account for the term of years over which the facility is to be financed. This term is generally tied directly to the power purchase agreement, which ensures the facility will generate sufficient revenues to repay the debt.⁶² The NEPOOL amendment fails to account for the debt term, leaving one to assume that the cash flows should be modeled using a debt term that is equal to a potentially much longer term—up to 35 years given their proposed definition of New Capacity Resource Economic Life. This assumption, however, is entirely unfounded. Or, alternatively, it leaves the debt term to be established in some different, wholly unspecified way that is not prescribed by the "New Capacity Resource Economic Life" definition that NEPOOL proposes—a path that would be similarly likely to engender significant, fact-intensive litigation over the "correct" debt amortization horizon to use for any given technology type.

Nor is this simply an academic failing. Extending the debt term of the facility directly affects the cash flows necessary in each year to repay that debt—a point that Ms. Powers illustrates in her supporting testimony with a simple example involving a mortgage.⁶³ Artificially extending the debt term artificially lowers the annual costs to service that debt, and in turn artificially lowers the ORTP value for the technology.

It also introduces other potential inaccuracies. Assuming 20 years of cash flows is reasonable in part because it reflects the industry's assumption and determination that a generating facility will produce stable revenues over this period based on a 20-year power purchase agreement. Beyond those 20 years, a cash flow analysis would have to account for the performance degradation that occurs with an aging facility, which impacts both the revenues it earns and the costs it incurs (increasing capital, operating, and maintenance expenditures) to repair and maintain the aging facility. NEPOOL's Economic Life proposal fails to account for either of these effects, and instead unreasonably assumes (in its application of the Economic Life proposal to its proposed ORTP values for solar and offshore wind) that there is no degradation in the efficiency of the technology, or increase in its costs, as it reaches the end of its operating or physical life. These assumptions are not reasonable, and could potentially have a significant impact on the cash flows.

NEPOOL itself seems to recognize that its "Economic Life" proposal is only a half-way measure, as it does not even apply the new definition to over half of the ORTP values calculated for FCA 16. Rather than establish, with evidence, the Economic Life of each of the 10 or so technology types for which ORTPs are calculated, it cherry-picks an Economic Life for only two technologies—offshore wind and photovoltaic solar. The ISO explains below its concerns with

virtually impossible to ensure that each technology type's Economic Life is being calculated on a comparable basis. Second, as addressed below, NEPOOL fails to apply the concept to all technology types for FCA 16, which negates any potential that its application would provide for greater comparability across technology types.

⁶² See Powers Testimony at 9-15 (discussing the relationship between the debt term and the power purchase agreement for a typical offshore wind facility).

⁶³ *Id.* at 12-13.

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the Economic Life values that NEPOOL employs for these two ORTP calculations. Equally troubling, however, is the fact that NEPOOL provides no rationale for selectively choosing to apply its proposed Tariff change to only these two technology types. This half-way application immediately produces a violation of the filed rate doctrine, as NEPOOL's proposal to treat two resources differently does not align with it proposes to be the filed rate for the calculation of the large majority of ORTPs,⁶⁴ and is arguably also unduly discriminatory in violation of the Federal Power Act.⁶⁵

Finally, the NEPOOL proposal is directly contrary to FERC precedent on the manner in which ORTP screening thresholds used in the context of the MOPR should be calculated. As CEA explains in its report, "it is important to have consistent financial assumptions across resource types in order to evaluate these ORTP values on a comparable basis."⁶⁶ As noted above, this assumption is consistent with FERC guidance that "default MOPR values should maintain the same basic financial assumptions, such as the 20-year asset life, across resource types … to ensure resource offers are evaluated on a comparable basis."⁶⁷

B. Offshore Wind

1. ISO-NE ORTP Evaluation for Offshore Wind

Interest in development of large-scale offshore wind facilities in New England has increased significantly in the last several years. Several state-regulated electric distribution companies in New England have, within the past few years, entered into long-term power purchase agreements for energy from proposed new offshore wind projects.⁶⁸

⁶⁴ The filed rate doctrine requires utilities to charge the rate that is on file with the relevant regulatory agency. *See Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 577 (1981) (defining the doctrine as one that "forbids a regulated entity to charge rates for its services other than those properly filed with the appropriate federal regulatory authority"). If NEPOOL is to have its way, the rate on file will include its Economic Life proposal, which it has failed to apply uniformly to all the ORTP values it proposes to update, thus applying a rate that is (or would be) "other than those properly filed with" the Commission.

⁶⁵ By applying its Economic Life proposal to *some* technologies, but not others, NEPOOL provides an undue preference or advantage to resources of certain technologies, without justifying the disparate treatment with respect to the remaining technology categories. *See Advanced Energy Management Alliance v. FERC*, 860 F.3d 656, 670 (D.C. Cir. 2017) (citing *Transmission Agency of N. Cal. v. FERC*, 628 F.3d 538, 549 (D.C. Cir. 2010) ("A rate is not 'unduly' preferential or 'unreasonably' discriminatory if the utility can justify the disparate effect.")). *See also Metro. Edison Co. v. FERC*, 595 F.2d 851, 857 (D.C. Cir. 1979) ("A difference in rate treatment is not unduly discriminatory when the difference is amply justified...").

⁶⁶ CEA Report at 80.

⁶⁷ Calpine Corporation v. PJM Interconnection, L.L.C., 169 FERC ¶ 61,239 (2019) at P 153.

⁶⁸ These projects include the planned 704 MW Revolution Wind project off the coast of Rhode Island and the planned 800 MW Vineyard Wind and 804 MW Mayflower Wind projects off the coast of Massachusetts. *See* National Renewable Energy Laboratory "Comparing Offshore Wind Energy Procurement and Project Revenue Sources Across U.S. States," Table A-2, p. 41, *available at available at* https://www.nrel.gov/docs/fy20osti/76079.pdf.

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ISO-NE therefore performed an ORTP evaluation for offshore wind for FCA 16. The ISO's consultants—CEA and Mott MacDonald—developed a detailed, bottom-up engineering-based cost estimate to develop, construct, and operate a large-scale offshore wind facility of similar size and location to those that are in development in New England presently.

As a result of this detailed evaluation, the ISO determined the offshore wind generation technology would have estimated costs that are above the Forward Capacity Auction Starting Price for FCA 16. Therefore, as explained above, no ORTP value is provided in the Tariff revisions in this filing for offshore wind. Instead, all capacity supply offers from new offshore wind resources seeking to participate in the FCM will continue to be subject to individual new resource offer floor price reviews performed by the IMM, pursuant to the existing MOPR in Section III.A.21.2 of the Tariff.

a. The ISO Employed the Same Methodology to Calculate the Cost of Entry for Offshore Wind that it Employed for Other Technologies in the ORTP Calculation

The testimony of Danielle S. Powers, Senior Vice President at Concentric, and the Mott MacDonald Offshore Wind ORTP Report explain the methods that CEA and Mott MacDonald employed to estimate an ORTP for the offshore wind technology, and walk through each step of the calculation. As Ms. Powers explains,⁶⁹ per the Tariff, they employed a discounted cash flow financial model that incorporated the capital expenses, operating costs, expected market revenue (including energy and Renewable Energy Certificate market revenue), and assumptions regarding project capital structure, debt and equity rates, depreciation, taxes and the discount rate, with the ORTP being set to "the year-one capacity price output from the model."⁷⁰ As with each other technology, this analysis was accomplished using a detailed, bottom-up engineering analysis of the costs to construct and operate a large-scale offshore wind facility.⁷¹

The details of the discounted cash flow analysis are set forth in Sections II and V of the Powers Testimony. The details of Mott MacDonald's capital cost estimation for the reference offshore wind facility are set forth in the Mott MacDonald Report. We refer the reader to these two documents, which are Attachments I-1e and I-1f to this filing, for the full calculation of the offshore wind ORTP. We highlight here several importance aspects of their analysis, and then explain the resulting calculation.

Size and Location of the Reference Project. The hypothetical offshore wind project modeled for the ORTP analysis has a nominal installed capacity of 800 MW. As Ms. Powers explains, "This size was selected because it is consistent with the size of several planned offshore wind projects off the coast of southeastern New England,"⁷² including the Revolution Wind, Vineyard Wind and Mayflower Wind projects. It is assumed that the project will be located off

⁶⁹ Powers Testimony at 3.

⁷⁰ Tariff Section III.A.21.1.2(b).

⁷¹ Powers Testimony at 3-4.

⁷² Powers Testimony at 6.

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the southeastern New England coast in the Massachusetts Offshore Wind Energy area (referred to as the "Massachusetts lease area"), and that it will interconnect into the existing New England high-voltage transmission system at Brayton Point, in Somerset, MA. As the Mott MacDonald Report explains, the Massachusetts lease area contains multiple adjacent lease areas for offshore wind development.⁷³ These areas are located in federal waters approximately 60 miles off the southeastern New England coast, and this is where new offshore wind development serving New England is taking place.⁷⁴ Brayton Point was chosen for the point of interconnection because of its more direct access to the to the 345 kV transmission network than other possible interconnection points, and because the existing electrical infrastructure at Brayton Point would help to minimize electric system upgrades.⁷⁵

Time Horizon for Financial Modeling. The ISO's financial analysis used a time horizon of 20 years, in accordance with the Tariff requirement that the analysis "look[] at 20 years of real-dollar cash flows discounted at a rate equal to the Weighted Average Cost of Capital consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties)."⁷⁶ As Ms. Powers notes, this assumption "is consistent with recently announced offshore wind projects, which have disclosed that they are being developed under 20 year PPAs."⁷⁷ This 20-year PPA term is therefore a financially appropriate duration for modeling the debt term of the facility—a component that can have a significant impact on the discounted cash flows of the facility. As Ms. Powers explains, "It is reasonable to assume that a lender would consider the time horizon of the PPA in providing financing for a generating facility and would rely on the timely repayment of the debt over the term of the PPA."⁷⁸

Capital Cost Calculation. Perhaps the most impactful input into the discounted cash flow analysis is the capital cost estimate to develop the offshore wind project. To estimate capital costs, Mott MacDonald leveraged their experience with offshore wind construction, engineering, and development. They have provided engineering and technical advisory services for offshore wind development in Asia, Europe and the United States, including in New England, and therefore have an understanding of the scope of work required to build an offshore wind project and the factors that have a significant impact on offshore wind project costs in New England specifically.⁷⁹

Based on this experience, Mott MacDonald performed a detailed and thorough bottom-up capital cost estimation for the reference offshore wind project. They began by defining the scope of work for the project, which "matched the needs of the project, from the size (power generation

⁷³ Mott MacDonald Report at 8.

⁷⁴ *Id.* A map of the Massachusetts lease areas is included as Figure 4.1 of the Mott MacDonald Report.

⁷⁵ *Id.* at 10.

⁷⁶ Tariff Section III.A.21.1.2(b).

⁷⁷ Powers Testimony at 10-11.

⁷⁸ *Id.* at 11.

⁷⁹ Mott MacDonald Report at 4.

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capacity) of the project, to weather conditions, to system interconnection requirements, to water depth, to turbine spacing requirements, to lease location and interconnection locations, the equipment redundancy required for reliability, and several additional factors" that are detailed in the Mott MacDonald Report.⁸⁰ They then undertook a cost estimation effort that relied primarily on their internal confidential database on costs for engineering, procurement, construction, and other related costs from actual prior offshore wind project engagements they have performed. Given their regional experience, Mott MacDonald also performed adjustments necessary to address New England region-specific conditions for development in the Massachusetts Offshore Wind Energy Area.⁸¹ This estimation effort, which is detailed in the Mott MacDonald Report, produced an estimated overnight capital cost value of approximately \$4.286 billion (in 2019 dollars), which is \$5,358/kW based on the 800 MW size of the project.⁸²

Application of the ITC. The 2021 Appropriations Act provided for an ITC of 30% for an offshore wind facility placed in service in 2025.⁸³ As discussed in detail in Section 4 of the Powers Testimony, this tax law impacts the cost accounting and tax liabilities of eligible new resources planning to participate in FCA 16; therefore, the tax law's impact was incorporated into the financial analysis determining the ORTP value for offshore wind. In that financial analysis, CEA assumed an offshore wind project's developer would fully monetize the ITC benefit.⁸⁴

The application of the ITC substantially decreases the total cost of the project to the developer. In simple terms, the ITC rate of 30% for offshore wind investments offsets a significant portion of the capital expense of developing the offshore wind project.⁸⁵ This has a significant impact on the ORTP value. The ORTP analysis is intended to estimate the minimum capacity revenue necessary for the project to be commercially viable, given its cost of capital. As noted in the Powers Testimony, in a hypothetical scenario in which there was no ITC for offshore wind investments, the project's minimum capacity revenue requirement would be approximately \$44/kW-month.⁸⁶ After incorporating the ITC in accordance with the 2021 Appropriations Act, the minimum capacity revenue requirement is approximately \$18/kW-month. Thus, although the ITC substantially lowers the requisite capacity revenue for a new offshore wind project to cover its total costs, the final capacity revenue requirement (at

⁸⁰ *Id.* at 3.

⁸¹ Id.

⁸² *Id.* at 18.

⁸³ The 2021 Appropriations Act also provided for an ITC of 26% for solar facilities, which is addressed in Section IX.C.3 of this transmittal letter.

⁸⁴ Powers Testimony at 19-20.

⁸⁵ *Id.* at 20.

⁸⁶ Powers Testimony at 21.

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approximately \$18/kW-month)—which would set the ORTP value for offshore wind—remains well above the Forward Capacity Auction Starting Price of \$11.978/kW-month.⁸⁷

The ISO-NE-Calculated ORTP Value for Offshore Wind. Section 5 of the Powers Testimony explains how CEA arrived at values for the various inputs into the discounted cash flow model, and then presents the offshore wind ORTP value. Of particular note: the calculation uses the same financial assumptions that are employed for the remaining ORTP values, as detailed in the CEA Report,⁸⁸ to arrive at an after-tax weighted average cost of capital value of 6.4 percent;⁸⁹ revenue offsets for the calculation total \$25.495/kW-month and include energy revenues,⁹⁰ Renewable Energy Credit (REC) revenues, scarcity revenues, and pay-for-performance revenues;⁹¹ and a qualified capacity value of 372 MW (which is approximately 46% of the 800 MW of installed capacity) is calculated, per the Tariff, using summer and winter reliability hours.⁹²

Using these inputs, as well as the estimate of the reference unit's capital costs as detailed above, CEA calculated an ORTP of \$17.948/kW-month for the offshore wind technology.⁹³ As Ms. Powers explains, "This is the estimate of the minimum capacity revenue needed for the reference offshore wind facility to be financially viable in the absence of any out-of-market revenue sources, and therefore would serve as the ORTP for offshore wind were the value not above the FCA 16 auction starting price. This value accounts for all the assumptions and calculations addressed in this testimony, the CEA Report, the CONE Addendum, the ORTP Addendum and the Mott MacDonald Report."⁹⁴

b. Mott MacDonald's Capital Cost Estimate Takes Account of Several Factors that Impact the Costs for Offshore Wind Development in New England Relative to Costs for Similar Projects in Other Locations

As noted above, one of the most significant components of the total cost for offshore wind development is its capital costs. These costs can differ significantly between regions for a number of reasons, including regulations and geographical features that impact the location and construction of the project, differences in the scope of work to be performed that define the costs

⁸⁷ This Forward Capacity Auction Starting Price value for FCA 16 is conditional upon the Commission's acceptance of the FCA 16 parameters submitted by ISO-NE in the Revised FCA 16 CONE Values Filing.

⁸⁸ CEA Report at Section 7.D.

⁸⁹ Powers Testimony at 26.

⁹⁰ The offshore wind facility is assumed to schedule all of its energy into the energy market as a price-taker and does not provide ancillary services. *See* Powers Testimony at 26-27.

⁹¹ Powers Testimony at 21-22.

⁹² Powers Testimony at 31-32.

⁹³ Powers Testimony at 32-33. As Ms. Powers notes, and as detailed above, this value is significantly impacted by the ITC. Without the ITC, the ORTP for the offshore wind facility would be \$44.421/kW-month.

⁹⁴ Id.

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for which the project developer is responsible (and those covered by other parties, such as a PPA counterparty or host utility), and the maturity of offshore wind development and its supporting infrastructure in the region. Several of these factors impacted Mott MacDonald's capital cost estimation for the 800 MW New England offshore wind project studied for the ORTP analysis. We discuss next the most significant of those factors, and review their potential impact on the offshore wind project's estimated capital costs. As noted below, these factors are of particular importance when comparing the cost estimates for the ORTP project in New England with other public data and information on offshore wind development.

Location of the Massachusetts Offshore Wind Energy Area. The location of the reference facility in the Massachusetts lease area has a significant impact on the cost of the project. As Mott McDonald explains, the reference offshore wind facility is located 60 miles from the landbased point of interconnection at Brayton Point (or, for that matter, from any other feasible point of interconnection for the project). This long distance is necessitated by the location of all the Massachusetts lease areas, which place the development of offshore wind projects beyond the range visible from land.⁹⁵ In comparison, it is common for European offshore wind project sites to be located a maximum of 30 miles offshore, and several publicly-available offshore wind cost references, including some for projects in the U.S., utilize 25-30 miles as the distance from land to the offshore site of the wind turbines.⁹⁶

As Mott MacDonald explains, "The distance out to sea significantly increases the cost of the large high-voltage cabling and the associated undersea costs."⁹⁷ They further explain:

If the ISO-NE offshore wind reference project were to only be 30 miles from the [point of interconnection], the cost for the export submarine cables would be cut in half (approximately \$292 million which would reduce the overall cost to approximately \$4 billion or \$4,993/kW).⁹⁸

There are two important points to highlight. First, the distance from the offshore wind turbines to the point of interconnection on land has a *significant* impact on the cost of the facility—in this study of the Massachusetts Offshore Wind Energy Areas, it adds an additional \$365/kW-month, or almost seven percent, to the capital costs when compared to the costs for a similarly sized facility in other parts of the world, or even some U.S. locations. Second, given this cost difference, when performing benchmarking or similar cost comparisons, it is critical to verify that differences in the distance offshore (along with all other important project requirement differences) are appropriately accounted for.⁹⁹

⁹⁵ Mott MacDonald Report at 19.

⁹⁶ Id.

⁹⁷ *Id.* at 10.

⁹⁸ *Id.* at 19.

⁹⁹ See Mott MacDonald Report at 19 ("Due to this cost variance, Mott MacDonald recommends evaluating the scope of work before one compares the respective reference cost to the ISO-NE offshore wind estimated capital cost.")
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Differences in Project Scope of Work that Directly Impact the Developers' Costs. The second point is reflective of another, related cost-driver for offshore wind in New England that distinguishes it from large-scale offshore wind development globally. As Mott MacDonald explains, "A significantly different scope of work for offshore wind projects is prevalent in some European countries...when compared to the United States."¹⁰⁰ This is because, in some countries, the costs of certain major components such as the offshore substation, the submarine export cabling, the landfall transition, and the electrical interconnect to the point of interconnection are funded by the European host utility, not the offshore wind project or its developer—and therefore are not accounted for in the developer's scope of work or capital costs.¹⁰¹ Mott MacDonald explains the cost implications of these differences:

"[I]if those components were (counter to fact) not included in the Mott MacDonald cost estimate for the New England offshore wind reference project, the total overnight capital cost would be reduced by roughly \$1.2 billion, which would reduce the total capital cost estimate to approximately \$3 billion (or, for reference, \$3,750/kW)."¹⁰²

Again, it is critical to account for these differences when comparing offshore wind capital costs to data for offshore wind development in other regions of the world.

Relative (Lack of) Maturity of Offshore Wind Development in the U.S. vs. Other Regions. The United States' inexperience with offshore wind development also impacts proposed new projects' capital costs. While offshore wind development costs in China and Europe have been decreasing over the years due, in large part, to their experience and the availability of necessary infrastructure to support construction of such facilities, the United States at this point has virtually no experience with the execution of large-scale offshore wind projects.¹⁰³ In addition to this lack of experience, the United States does not yet have available the specialized vessels and supporting onshore infrastructure for staging and construction of offshore wind facilities.¹⁰⁴ All of these factors will increase the costs that a developer must incur in developing a large offshore wind project in New England at present; moreover, these factors will tend to raise the costs of development in New England (and the U.S. generally), relative to regions where significant offshore wind development has already taken place.

Regional Differences Within the U.S. Finally, it is important to note that costs to develop an offshore wind project may also differ between regions of the United States as well, for a number of reasons. Mott MacDonald notes that distance to shore, water depth, and distance to the point of interconnection can all vary between regions of the United States, and can all impact

¹⁰⁴ *Id.* at 19.

¹⁰⁰ *Id.* at 18.

¹⁰¹ *Id*.

 $^{^{102}}$ Id.

¹⁰³ Mott MacDonald Report at 19 (noting that "China and Europe represent approximately 22% and 75% of the current global offshore wind installed capacity [27,000 MW], respectively (with the US market accounting for roughly 0.2% of the current global offshore wind installed capacity.").

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the cost of the development.¹⁰⁵ As noted above, the distance from shore of the Massachusetts lease area is double that included in cost references for some U.S. offshore wind developments,¹⁰⁶ and this area is also in relatively deep water.¹⁰⁷ Both of these factors may result in the reference facility being more expensive to construct than a facility in other regions of the United States.

c. The ISO Benchmarked the Mott MacDonald Capital Cost Estimate Against Relevant, Publicly-Available Data on Capital Costs for Large-Scale Wind Projects

Recognizing the role that capital costs play in the ORTP calculation for the offshore wind technology, as well as the significant difference between the ISO and certain stakeholders regarding the appropriate capital costs of offshore wind, the ISO requested that CEA perform a benchmarking analysis of Mott MacDonald's capital cost estimate against other, relevant, publicly-available data on capital costs for large-scale offshore wind projects. CEA's review of their benchmarking analysis is provided in Section 6 of the Powers Testimony. We summarize here the analysis that CEA performed, as well as the central conclusions.

CEA reviewed publicly available information on offshore wind projects currently in development, including information published by the U.S. Energy Information Administration ("EIA"), the Department of Energy ("DOE"), and the New York State Energy Research and Development Authority ("NYSERDA"). In addition, they reviewed several sources of information on global offshore wind installations, including European projects where publicly-available estimates of construction costs were available.¹⁰⁸

Of the information reviewed, CEA found only a single series of studies—commissioned by EIA and performed by the engineering firm Sargent & Lundy—that CEA could confirm was based on a professional, bottom-up, engineering-based cost analysis and that appropriately estimated costs on a regional basis (*i.e.*, taking account of the types of region-based cost differences discussed above).¹⁰⁹ CEA found that, with respect to the remaining studies where the data sources were transparent, the vast majority were based upon installed costs of commissioned offshore wind projects in China and Europe (where the bulk of operating offshore wind projects are located), with no apparent adjustments for regional differences, variation in project scope, or

¹⁰⁵ *Id.* at 18.

¹⁰⁶ For Example, Table 22-1 of the U.S. Energy Information Administration's Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies (page 162) states that an offshore cable length of 30 miles was modeled. *See*

https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

¹⁰⁷ Mott MacDonald Report at 21.

¹⁰⁸ Powers Testimony at 33.

¹⁰⁹ *Id.* These studies are discussed at 35 of the Powers Testimony.

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the variation in whether significant costs are incurred by the host utility or the offshore wind developer.¹¹⁰

CEA reviewed two EIA studies based (in significant part) on the bottom-up capital cost estimates performed by the engineering firm Sargent & Lundy.¹¹¹ The studies are particularly useful as a benchmark for Mott MacDonald's capital cost estimate, both because of the bottom-up, engineering-based method used by Sargent & Lundy to estimate the capital costs and because the EIA (and underlying Sargent & Lundy) studies made specific adjustments to account for regional offshore wind development costs. Of particular interest for purposes of benchmarking the Mott MacDonald estimated capital costs, both EIA studies provide specific New England-estimates of offshore wind capital costs.

The 2021 and 2020 EIA studies' final estimates for offshore wind capital costs applicable to New England are \$6,360/kW and \$5,446/kW, respectively.¹¹² Because they are specific to New England, they are instructive for benchmarking Mott MacDonald's independently-performed capital cost estimate. As Ms. Powers explains, the 2021 and 2020 EIA studies include a 25% adjustment for the uncertainties associated with technologies that are the first of their kind to be developed, at large scale, in the U.S.¹¹³ As noted above, Mott MacDonald cited to these uncertainties as a reason why costs of offshore wind development in the U.S. will likely be higher at this time than costs in Asia or Europe, which have more experience with offshore wind development. In addition, the 2021 and 2020 EIA studies include a locational adjustment for construction and development in New England.¹¹⁴ This adjustment is also consistent with Mott MacDonald's analysis, though as Ms. Powers notes, a significant factor in locational cost differences—the longer distance of the Massachusetts lease area from shore—is not fully accounted for in Sargent & Lundy's cost estimate.¹¹⁵

The central point is that Sargent & Lundy's independently-performed, bottom-up capital cost estimates, when regional differences are accounted for, provide capital cost estimates that are within the same range of—but are higher than—Mott MacDonald's capital cost estimate. As Ms. Powers concludes: "The regional bottom-up engineering cost-based studies provide a corroborating, independent benchmark of offshore wind capital costs for New England. These

¹¹¹ Id.

¹¹² *Id.*

¹¹³ *Id*.

¹¹⁴ *Id*.

¹¹⁰ *Id*.

¹¹⁵ *Id.* In contrast, the PJM application, which is included in row 3 of the Offshore Wind Regional Bottom-up Study Summary table on page 34 of the Powers Testimony does not include the EIA's 25% adjustment for the uncertainties associated with technologies that are the first of a kind to be developed in the U.S. *See* Powers Testimony at 36. Nor does it include any location adjustment for construction and development costs in New England. *Id.* For these reasons, it is not directly applicable for benchmarking the capital costs of offshore wind development in New England, but was included in CEA's analysis for completeness given its reliance on the Sargent & Lundy data (without adjustments). *Id.*

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studies represent costs that more closely resemble the costs that may be expected to be incurred for an offshore wind project located in the Northeast."¹¹⁶

CEA also reviewed a range of other that were cited during stakeholder discussions by the proponents of NEPOOL's \$0.000/kw-month ORTP value for offshore wind. These included studies from the National Renewable Energy Laboratory ("NREL"), the U.S. Environmental Protection Agency ("EPA"), Lazard, a report from Dominion Energy that was included as part of a 2020 Integrated Resource Plan filed with the Commonwealth of Virginia, studies by the International Renewable Energy Agency ("IRENA") as well as a white paper produced by NYSERDA.¹¹⁷ Ms. Powers explains in her supporting testimony that "these studies do not provide values that are appropriate for, or applicable to, the U.S. or New England,"¹¹⁸ as they rely greatly, and in some cases exclusively, on global cost data that does not account for the regional differences that determine the development costs for an offshore wind project in New England, or they do not reveal the data sources upon which they are based. A summary of Ms. Powers' detailed review of these studies is provided in her supporting testimony,¹¹⁹ and is addressed in greater detail below in the discussion of NEPOOL's proposed alternative offshore wind ORTP calculation.

Fundamentally, for an offshore wind capital cost study to be useful for benchmarking a large-scale facility in New England, the scope of work in those studies must be comparable, and the studies must transparently address regional differences that can have significant impacts on costs. None of the studies from NREL, DOE, IRENA, the EPA, Lazard, Dominion or NYSERDA meet these requirements, and therefore they are not informative for benchmarking Mott MacDonald's independent, bottom-up capital cost estimate for new offshore wind projects in New England.

2. Evaluation of the NEPOOL-Proposed Offshore Wind ORTP Value

During discussions with stakeholders on the ORTP update, a consortium of stakeholders presented an alternative proposal for a \$0.000/kW-month ORTP value for offshore wind. That proposal ultimately gained the support of sufficient stakeholders, and is therefore included in the package of NEPOOL-supported ORTP values.

The methodology employed by the proponents of the NEPOOL-supported offshore wind ORTP is, in certain respects, similar to the method employed by the ISO. But the differences are significant. The proponents employed their own "inferred capital cost" method to develop a substantially lower capital cost value. They further used their Economic Life proposal to extend the discounted cash flow analysis from the Tariff-required 20 years to 25 years. Using these values, the proponents calculated the ORTP value using a modified version of CEA's publicly-

¹¹⁹ *Id.* at 37-47.

¹¹⁶ *Id.* at 38.

¹¹⁷ The report name, year published, underlying source of data, and estimated offshore wind capital cost for these studies are shown in the Offshore Wind Other Studies Summary table of the Powers Testimony at 39.

¹¹⁸ Powers Testimony at 39.

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available discounted cash flow model. This produced an ORTP value that was below \$0.000/kW-month, and therefore the proponents set their alternative ORTP for offshore wind at \$0.000/kW-month.¹²⁰

There are two defining assumptions behind the NEPOOL proposal on offshore wind that differ from the corresponding values determined by CEA and Mott MacDonald. The first is that NEPOOL applies its Economic Life proposal to the offshore wind ORTP analysis, to calculate discounted cash flows over a 25 year period rather than the 20 year period that is required under the Tariff. The second assumption is that the NEPOOL-supported alternative assumes a much lower total capital cost for offshore wind development, at \$3,326/kW on an installed capacity basis.¹²¹ In contrast, the total capital cost for offshore wind calculated by Mott MacDonald of \$5,328/kW. These two assumptions are inputs into the discounted cash flow analysis used to calculate the ORTP value for offshore wind, and are sufficiently material that NEPOOL's discounted cash flow analysis results in a \$0.000/kW-month ORTP value.

Below, we discuss the ISO's concerns with these two assumptions, as these two assumptions are the entire basis for the different ORTP values for offshore wind put forth by the ISO and NEPOOL in this proceeding. In fact, to emphasize this point, if these two assumptions—the 25-year "Economic Life" and the \$3,326/kW capital cost assumption—are used in CEA's discounted cash flow model and analysis, the resulting ORTP value is \$0.000/kW-month for offshore wind. Both of these NEPOOL-supported assumptions are unrealistic "show-stoppers" for the ISO.

a. NEPOOL's Use of Its Economic Life Proposal in its Discounted Cash Flow Analysis Produces an Artificially Low ORTP for Offshore Wind

The NEPOOL-proposed Offshore Wind ORTP value uses its Economic Life proposal to assume a 25-year financial modeling horizon in its ORTP calculation. Stated in simple terms, NEPOOL calculates debt repayments, operating revenues, and a return on equity for offshore

¹²⁰ We note that, to determine their assumed lower total capital cost, the proponents also used an *additional*, privately-developed discounted cash flow model (hereafter, the "Daymark DCF model") for offshore wind. We discuss that Daymark DCF model and its use further below. For the sake of clarity, however, it is useful to note that because of the retention of Daymark, in the stakeholder process there were *two* different discounted cash flow models, developed by two different consultants (*i.e.*, CEA and Daymark), involved in discussion of the ORTP for offshore wind. These two different models were not used by the proponents of the alternative ORTP value as "competing" discounted cash flow models. Rather, to our knowledge, the proponents used *both* of the models, albeit for different purposes. Specifically, the proponents' privately-developed Daymark DCF model was used to support, in part, proponents' assumed lower total capital cost for offshore wind in New England (and only for that narrow purpose). Given that assumed lower total capital cost assumption, the proponents then returned to the CEA-developed discounted cash flow model, and employed the CEA-developed discounted cash flow model to calculate an ORTP value *given* the proponents' (lower) assumed total capital cost outlays for an offshore wind project.

¹²¹ See RENEW Northeast, Offshore Wind ORTP Calculation: Renew Amendment on Capital Costs and Tax Credit Assumptions, prepared for the November 9-10, 2020 NEPOOL Markets Committee meeting, at slide 7, *available at* https://www.iso-ne.com/static-

assets/documents/2020/11/a4_b_x_renew_presentation_offshore_wind_ortp_amendment.pdf.

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wind using discounted cash flows assuming a 25 year horizon, rather than the 20-year period prescribed by the current Tariff.

The primary impact of the 25-year modeling horizon (*i.e.*, what NEPOOL terms its "Economic Life" assumption) for offshore wind is to reduce the annual capacity revenue that is necessary to recover the costs of the unit (including the expected return on equity). In effect, the period of time over which those costs can be recovered with market revenue is spread out for an additional five years, and the period of time over which the project's initial debt must be repaid to its lenders is similarly spread out for an additional five years. This, in turn, reduces the revenue that the resource needs to recover through the capacity market (in the absence of any "out of market" contract revenue), and therefore reduces the ORTP value.

ISO-NE has explained in Section IX.A its significant concerns with the extension of the discounted cash flow analysis beyond 20 years, and those same objections apply to NEPOOL's proposal to do so here for the offshore wind ORTP analysis. We address here our particular concerns with the application of the longer modeling horizon (*i.e.*, NEPOOL's Economic Life proposal) assumed in the NEPOOL-proposed offshore wind ORTP.

During stakeholder discussions, the proponents of the NEPOOL offshore wind ORTP provided as support for the assumed 25 year project life a report summarizing the results of a "brief survey of U.S. wind project developers, sponsors, financiers, and consultants."¹²² The survey looked to "clarify trends in the expected useful life of land-based wind power plants in the United States."¹²³ According to the report, 12 out of 21 professionals surveyed use 30 years for the "useful life" assumptions for *onshore* wind facilities, and another six use either 25 years or between 25 and 30 years.¹²⁴ From this survey report, the proponents of the NEPOOL-proposal apparently settled on 25 years for the useful life of an *offshore* wind facility.

The ISO does not have reason to question the validity of the survey report *per se.* It is entirely unclear, however, why—and the extent to which—a survey of professionals regarding their views on the useful life of *onshore* wind facilities is relevant to determining the useful life of an *offshore* wind facility, given the vast differences in operating characteristics and conditions of the two types of facilities. Indeed, it seems likely that to determine the relevance of the onshore wind survey data, one would need to perform an engineering analysis of the difference between onshore and offshore wind facilities, to assess whether the useful life of the former is a reasonable proxy—or even a plausible proxy—for the useful life of the latter. To date, it does not appear that this sort of analysis (or, for that matter, any analysis at all) has been performed.

¹²² Asset Lifetimes for the ORTP Calculation: A Proposed Amendment, slide 6, presented to the NEPOOL Markets Committee on September 8-10, 2020, *available at* https://www.iso-ne.com/static-

assets/documents/2020/09/a6_a_v_renew_amendment_asset_lifetime_for_ortp_calculation.pdf. Benchmarking Anticipated Wind Project Lifetimes: Results from a Survey of U.S. Wind Industry Professionals, Ryan Wiser and Mark Bolinger, Lawrence Berkeley National Laboratory, September 2019 at 1 ("Berkeley Wind Survey"), *available at* https://eta-publications.lbl.gov/sites/default/files/wind_useful_life_report.pdf.

¹²³ *Id*.

¹²⁴ *Id.* at 2.

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Thus, the relevance of the survey report for NEPOOL's proposed 25 year useful life for the offshore wind ORTP has not been established.

However, even if one could justify the use of the onshore wind survey as the basis for a 25 year "Economic Life" for an offshore wind facility operating in a marine environment, using this extended term in the calculation of an offshore wind ORTP raises a number of significant concerns that NEPOOL failed to address during the stakeholder process. We summarize those concerns here:

• The discounted cash flow analysis as performed by NEPOOL appears to have assumed—with no support whatsoever—a debt term equal to its 25-year "Economic Life." This assumption is not reasonable, and has the effect of artificially lowering the project costs, and therefore artificially lowering the ORTP for the technology. As Ms. Powers explains in her supporting testimony, the large-scale offshore wind projects slated for development in New England have each entered into 20-year PPAs.¹²⁵ "Beyond the PPA term, there is significant uncertainty around offshore wind revenues and operating costs. Therefore, it is not reasonable to conclude that lenders would originate debt prior to a project's initial development for a horizon greater than the initial contracted revenue period provided under the PPA of 20 years."¹²⁶

Section IX.A above addresses the consequences of assuming a longer debt life than is reasonable for such a project. As Ms. Powers explains: "The assumed debt life is a determining factor in the calculation of the ORTP value. If one assumes a debt life in excess of the PPA term, the true cost of the facility is spread over a longer period of time and further into the future, when the time value of money is further discounted. This makes the project cost (net of offsetting revenue from energy sales) appear lower, so that the calculation does not reasonably reflect the actual costs of the project."¹²⁷

• Similarly, unless energy market and Renewable Energy Certificate market revenue beyond the first 20 years are adjusted for declining project output due to performance degradation over time as a facility ages (which they are not in NEPOOL's proposed ORTP), the ORTP calculation will incorrectly assume a constant revenue stream up to and through the assumed extended years of the facility's life. This is an unreasonable assumption since the facility's ability to generate revenues will decrease with an extended operating life, as the efficiency of the unit degrades and it faces the increased likelihood of equipment failure.

¹²⁵ Powers Testimony at 10-11.

¹²⁶ *Id.* at 11. The Berkeley National Laboratory study which the NEPOOL proponents rely on for their 25-year "Economic Life" recognize this same point, stating that "Lenders are generally focused on ensuring that loans are repaid during the term of the PPA...." Berkeley Wind Survey at 6.

¹²⁷ *Id.* at 12.

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• Finally, during the later years of a project's life, capital expenditures will increase as maintenance and repair costs increase. Again, unless these additional capital expenditures are accounted for (which they are not in NEPOOL's proposed ORTP), the resulting ORTP value will not provide an accurate reflection of the cash flows required for the offshore wind project to be financially viable.¹²⁸

In short, while it is mechanically possible to extend the financial time horizon assumed in the discounted cash flow calculation for ORTPs—as NEPOOL has done—that does not result in realistic (or even plausible) ORTP values. Rather, to model a new offshore wind project over a longer (*e.g.*, 25-year) time horizon sensibly requires making a number of decisions and significant adjustments to the calculation methodology. None of those have been performed or accounted for in NEPOOL's proposed 25 year discounted cash flow analysis for offshore wind. Further, each such decision and adjustment must be supported by data and evidence that, in turn, must be transparently documented so that it may be evaluated for reasonableness and accuracy. That work simply has not been done for NEPOOL's proposed offshore wind analysis; as a result, there is no basis (or even likelihood) to conclude that the resulting NEPOOL-supported ORTP value is accurate or reasonable. For this reason alone, in addition to the reasons provided above in Section IX.A on NEPOOL's Economic Life proposal, the ISO opposes NEPOOL's proposed offshore wind ORTP value.

b. NEPOOL's Proposed "Inferred Capital Cost" Value Cannot be Benchmarked Against Relevant, Publicly Available Offshore Wind Capital Cost Estimates

As noted at the outset of this Section IX.B.2, the NEPOOL-supported ORTP for offshore wind assumes a much lower total capital cost for offshore wind development, at 3,326/kW on an installed capacity basis, than the total capital cost value detailed in the Mott MacDonald report (*i.e.*, 5,328/kW, as discussed previously in Section IX.B.1).¹²⁹

To obtain its lower total capital value, proponents of the NEPOOL-supported alternative ORTP did not perform a bottom-up, engineering-based estimation of the capital costs for offshore wind ORTP; instead, they "inferred" a total capital cost value from an analysis and model of power purchase agreements for recent large-scale wind projects in New England, in combination with a survey of various third-party offshore wind capital cost estimates in the public domain. Through this combination, it established a capital cost value of \$3,326/kW. We discuss presently the ISO's concerns with NEPOOL's capital cost estimation, and its resulting impact on the offshore wind ORTP.

The proponents of the NEPOOL offshore wind ORTP retained Daymark Energy Advisors (a management and investment advisory firm) to calculate implied capital expenditures for proposed offshore wind projects in New England. Their approach involved constructing a separate discounted cash flow model, which incorporated the contractually-stipulated payments from four publicly-available Power Purchase Agreements ("PPAs") for proposed offshore wind

¹²⁸ See Powers Testimony at 3.

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projects. Two cases for each PPA were modeled (based upon differing assumptions regarding potential capacity revenue), to "infer" the capital costs at which the proposed new offshore wind projects would just "break even" based upon the contractually-stipulated revenue streams, the capacity revenue assumptions, and other offshore wind performance and financial modeling assumptions. The weighted average of the implied capital costs from the eight cases modeled was calculated and stated, in the stakeholder process, to be \$3,326/kW (in 2019 dollars).¹³⁰

The difference between the capital costs estimated by Mott MacDonald using its bottomup engineering-based analysis, and the "inferred" capital cost used by the proponents of the NEPOOL-supported alternative, is substantial. The ISO's capital cost estimate totals \$4.3 billion; or \$5,358/kW (2019\$); the inferred capital costs proposed by NEPOOL are approximately 40 percent lower, totaling \$2.6 billion, or \$3,326/kW (2019\$).

ISO-NE has significant concerns with the inferred capital cost approach employed by the proponents of the NEPOOL proposal. While some of these concerns may simply reflect a lack of detail and transparency provided by the proponents of the NEPOOL proposal during the stakeholder process, and thus may be addressed in NEPOOL's filing in this proceeding, others are more fundamental.

First, it is not clear that the inferred capital cost approach is consistent with the Tariff requirements for calculating ORTP values. Section III.A.21.1.2(b) of the Tariff states in relevant part: "Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the FCM to yield a discounted cash flow with a net present value of zero for the project." In point of fact, NEPOOL's proposal "backs into"—that is, it infers—a capital cost value for offshore wind. In contrast, each other input into CEA's discounted cash flow model is derived from actual data on the relevant input—data that can be verified and evaluated on its face. The same cannot be said of the inferred capital cost value, as there is simply no underlying data that explains what comprises the components of (indeed, there are no components of) the capital cost NEPOOL assumes.

Put another way, it is not at all clear that an *inferred* capital cost value is, in fact, a *capital cost* value. While there is no established "dictionary definition" of the term "capital cost," the *Wikipedia* entry for capital cost starts with: "Capital costs are fixed, one-time expenses incurred on the purchase of land, buildings, construction, and equipment used in the production of goods or in the rendering of services. In other words, it is the total cost needed to bring a project to a commercially operable status."¹³¹ This explanation makes clear what is missing in the NEPOOL-proposed use of an implied capital cost value—there is no explanation of the actual *costs* that comprise the total capital cost.

¹³⁰ See RENEW Northeast, Offshore Wind ORTP Calculation: Renew Amendment on Capital Costs and Tax Credit Assumptions, prepared for the November 9-10, 2020 NEPOOL Markets Committee meeting, at slide 7, *available at* https://www.iso-ne.com/static-

assets/documents/2020/11/a4_b_x_renew_presentation_offshore_wind_ortp_amendment.pdf.

¹³¹ Wikipedia entry for "capital cost," *available at* https://en.wikipedia.org/wiki/Capital_cost.

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Equally significant is that the inferred capital cost value is entirely dependent on the soundness of the privately-developed, alternative cash flow model that Daymark employed (*i.e.*, the Daymark DCF model) to derive it. However, to date, there has not been sufficient transparency about how this model functions. An analysis performed by the IMM indicated that small adjustments to the inputs to the model could have *significant* impacts on the resulting value, in some cases a 45 percent change in the capital cost value resulting from minor adjustments to its inputs.¹³² Additional analysis is necessary to understand how the alternative Daymark DCF model functions before it can be relied upon as providing a reasonable estimate of a capital cost.

Finally, the Daymark DCF model employed to derive NEPOOL's inferred capital cost assumes the same, tenuous 25-year "Economic Life" assumption and cash flow modeling horizon that the NEPOOL proposal employs for deriving its \$0.000/kW-month offshore wind ORTP. Thus, the implied capital cost calculation performed by Daymark contains the same questionable assumptions about a 25-year debt term—an assumption inconsistent with the durations of the very PPAs used to derive the value. The additional revenues afforded by an extended modeling horizon will artificially decrease the inferred capital costs (assuming all other inputs remain constant).

NEPOOL has attempted to benchmark its inferred capital cost value against other, publicly-available offshore wind capital cost estimates. ISO-NE believes that the studies that NEPOOL looks to for its benchmarking are unrepresentative of the capital costs for a large-scale offshore wind development in New England.

In various stakeholder presentations on the NEPOOL-supported proposal, proponents benchmarked their inferred capital cost value against publicly-available offshore wind capital cost studies and reports. CEA evaluated each of the publicly available studies relied upon by the proponents of the NEPOOL-supported proposal, which include: the 2018 and 2019 IRENA Renewable Power Generation Cost studies, the NREL Vineyard Wind PPA Analysis and NREL's 2020 Annual Technology Baseline, the 2020 NYSERDA-commissioned study, the EPA: 2018 IMP Platform study (which was based on 2016 NREL data), a 2019 study by Lazard, a report from Dominion Energy that was included as part of a 2020 Integrated Resource Plan filed with the Commonwealth of Virginia, the DOE 2018 Offshore Wind Technologies Market Report, and PJM's 2020 Recalculation of the default MOPR Offer Floor Prices (which was based on an unadjusted Sargent & Lundy bottom-up estimate).¹³³

¹³² See IMM memo to NEPOOL Markets Committee, November 9, 2020, *available at* https://www.isone.com/static-assets/documents/2020/11/a4_imm_memo_re_ucs_renew_offshore_wind_amendment.pdf ("In fact, the IMM has evaluated the sensitivity of the discounted cash flow model and found that the offer floor price can be reduced by as much as 45% by making small adjustments in a number of the input variables to that equation. The discounted cash flow model is sensitive to the inputs and, therefore, the inferred capital cost value will be too.").

¹³³ See RENEW Northeast, Offshore Wind Capital Costs and ITC for ORTP Calculation: A Proposed Amendment, prepared for the October 6-8, 2020 NEPOOL Markets Committee meeting, at slides 24-25, *available at* https://www.iso-ne.com/static-assets/documents/2020/10/a5_b_vi_ucs_amendment_no_1.pdf; *see also* Powers Testimony at 40.

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The Powers Testimony explains the detailed analysis that CEA performed of each of the studies relied upon by the proponents of the NEPOOL offshore wind ORTP, and contains a summary table of the report name, year published, the underlying source of data, and the capital cost value in 2019 dollars, as well as links to each of the reports.¹³⁴ The offshore wind capital cost estimates in these studies vary widely. More importantly, however, as Ms. Powers explains in her supporting testimony, the studies "do not provide values that are appropriate for, or applicable to, the U.S. or New England." As the Powers Testimony explains, they rely greatly, and in some cases exclusively, on global cost data that does not account for the regional differences that determine the development costs for an offshore wind project in New England, or the source of the data is not transparent, making it impossible to assess their relevance for benchmarking the capital costs of a New England-based project.¹³⁵ Specifically:

- The NREL Vineyard Wind PPA analysis relies exclusively on capital cost data from Europe, specifically Bloomberg New Energy Finance (2018) data for the prevailing average CapEx for offshore wind projects in Europe.¹³⁶
- The DOE study relies on third-party data sources that utilize global cost estimates, primarily from Europe.¹³⁷
- The NREL 2020 Annual Technology Baseline also is sourced heavily from global data, calibrated based on cost trends in both the US and Europe, and is not adjusted for regional cost differences. In fact, NREL's public online cost estimation workbook provides various cases that account for relevant New England regional factors such as a location further from shore (48 miles rather than 22 miles), with capital cost estimates increasing as distance increases, from \$3,666/kW (2019\$) to \$5,044/kW (2019\$)—the latter value being close to Mott MacDonald's \$5,358/kW capital cost estimate.¹³⁸
- The two IRENA studies wholly rely on European and other global projects for their cost estimates. In addition, IRENA acknowledges that the facilities for which its estimates are based have project scopes of work that vary widely from country to country, rendering them ill-suited for comparison to offshore wind capital costs in New England.¹³⁹
- EPA's documentation for its Integrated Planning Model Power Sector Modeling Platform 2018 Reference Case provides a base value as well as suggested adders

¹³⁴ Powers Testimony at 39, Offshore Wind Other Studies Summary table.

¹³⁵ See Powers Testimony at 37-47 for the evaluation of these studies.

¹³⁶ *Id.* at 40.

¹³⁷ *Id.* at 41.

¹³⁸ *Id.* at 40.

¹³⁹ *Id.* at 44-45.

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to reflect regional cost differences and impacts from short-term risks.¹⁴⁰ Adjusted for these adders, the capital cost estimate in the EPA report is \$6,705/kW, more comparable to (though much higher than) that derived by Mott MacDonald.¹⁴¹ Further, the underlying data in the study is based on the 2016 NREL Annual Technology Baseline, and so the 2020 NREL Annual Technology Baseline is deemed more appropriate for benchmarking purposes.¹⁴²

- PJM's 2020 recalculation of its default offer floor price, which employed the Sargent & Lundy capital cost estimate that EIA relied upon for its studies, does not include any locational adjustment for construction and development costs in New England, and also does not include the adjustment for the uncertainties associated with technologies that are the first of a kind to be developed in the U.S., which EIA applied in its 2020 and 2021 studies (as noted previously).¹⁴³
- The source of the data reported in the Lazard: 2019 Levelized Cost of Energy report is not transparent, and the report acknowledges that the estimate does not encompass the full scope of the development costs.¹⁴⁴ Thus, it is not reasonable to use the resulting estimate as a basis for benchmarking an "all-in" capital cost estimate, as is expected for us in the development of the ORTPs.¹⁴⁵
- The source of data for the Dominion Integrated Resource Plan value referenced in proponents' proposals is also not transparent. The plan provides a Levelized Cost of Energy for Offshore wind, and notes that it was derived by "a busbar (i.e., LCOE) screening model," but there is no detail regarding the methodology or assumptions used in the model.¹⁴⁶
- The white paper prepared by the Renewables Consulting Group ("RCG") on behalf of NYSERDA "to assess the deployment, cost and benefit of incremental renewable energy resource under Tier 1 of the Renewable Energy Standard (RES) and the Offshore Wind Standard"¹⁴⁷ in New York is problematic, for two primary

¹⁴² *Id*.

¹⁴⁵ *Id*.

¹⁴⁰ During stakeholder discussions of the offshore wind ORTP, proponents of the EPA study cited the unadjusted "base" capital cost estimate, and did not consider regional cost differences and impacts from short-term risks.

¹⁴¹ Powers Testimony at 45.

¹⁴³ *Id.* at 36.

¹⁴⁴ *Id.* at 45-46.

¹⁴⁶ *Id*. at 46.

¹⁴⁷ White Paper on Clean Energy Standard Procurements to Implement New York's Climate Leadership and Community Protection Act, Case 15-E-0302, June 18, 2020, Appendix A – Cost Analysis, pg. 3; *available at* http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0302&submit=Search; (service number 258) ("NYSERDA White Paper").

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reasons. First, its scope of work differs from a scope of work that would reflect the complete development costs for a large-scale offshore wind project in New England. The scope in the NYSERDA study excludes costs such as working capital, owner's development costs, and financing fees, which together account for approximately 10% of the total installed cost for the offshore wind project that was the subject of the Mott MacDonald analysis.¹⁴⁸ This is a glaring omission. Second, even the RCG "base case" capital cost assumptions are opaque and not available on the record, being developed by RCG with no detailed project scope of work and little supporting description (beyond that RCG's modeling "contains cost data and forward-looking cost assessments through 2040").¹⁴⁹ Ms. Powers concludes, "Without provenance for their cost data, there is no basis to evaluate their reasonableness or accuracy. As a result, the opacity and unstated basis for their estimates means their validity cannot be reasonably evaluated, and as a consequence, I did not consider these sources in our benchmarking exercise."¹⁵⁰

As we explained above, Mott MacDonald's bottom-up engineering analysis accounted for factors and conditions specific to New England that explain why the costs of developing a large-scale offshore wind project in New England would differ substantially from costs of offshore wind development in other locations—including costs related to the location (60 miles) offshore of Massachusetts Offshore Wind Energy Areas; differences in the scope of work borne by the developer versus host utility that can substantially impact the developer's total capital costs; "first to market" costs resulting from the lack of maturity of U.S. offshore wind development; and other regional cost differences. These are not costs that a developer in New England can avoid, and thus must be reflected in *any* potentially competitive FCM offer from a new offshore wind resource in New England. None of the studies or data sources that the proponents of the NEPOOL offshore wind ORTP value rely upon appear to account for these cost factors, and thus they are ill-suited to benchmark offshore wind capital costs in New England.

In summary, the NEPOOL proposal does not include a reasonable, substantiated estimate of the capital costs for the development of a large-scale offshore wind project in New England. The inferred nature of the value itself means that it is not, in fact, an estimate of capital costs, and NEPOOL's benchmarks demonstrate that the value is an unrealistically low estimate of the capital costs relevant to a project in New England. For these reasons—which are separate and independent from the concerns with NEPOOL's use of its Economic Life proposal—the ISO opposes NEPOOL's proposed \$0.000/kW-month ORTP value for offshore wind.

¹⁴⁸ Powers Testimony at 43.

¹⁴⁹ NYSERDA White Paper at 28.

¹⁵⁰ Powers Testimony at 44.

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C. Photovoltaic Solar

As the installed cost of photovoltaic solar facilities has decreased dramatically in recent years, the ISO performed an ORTP calculation for this technology type. Concentric's initial ORTP calculation for a 20 MW fixed-tilt solar array, located in Connecticut, was above the auction starting price.¹⁵¹

Subsequently, in late December 2020, Congress signed into law the 2021 Appropriations Act, which provides an extension of the beginning of construction deadline for the ITC for photovoltaic solar.¹⁵² The 2021 Appropriations Act provides an ITC of 26 percent to photovoltaic solar technologies that begin construction by December 31, 2022. The ISO assumes that resources that receive a Capacity Supply Obligation in FCA 16, scheduled for February 2022, will begin construction by the end of 2022 to avail themselves of this ITC. As a result, the ISO is including the full 26 percent ITC in its calculation of the ORTP for the photovoltaic solar technology for FCA 16.¹⁵³ Application of the 26 percent ITC reduces the ORTP for photovoltaic solar from above the starting price to \$1.381/kW-month.¹⁵⁴

NEPOOL supported an alternative that reduces the photovoltaic solar ORTP to \$0.000/kW-month. This alternative value reflects the application of the NEPOOL Economic Life proposal to increase the assumed solar photovoltaic project life in the discounted cash flow analysis from the Tariff-required 20 years to an assumed value of 30 years. The inputs and modeling used to obtain the ISO-proposed ORTP value and the NEPOOL-proposed ORTP value for photovoltaic solar are otherwise the same. As with the offshore wind ORTP, the primary impact of extending the project life to 30 years is to reduce the annual revenues that are necessary to recover the costs of the unit. This, in turn, reduces the revenues that the resource needs to recover through the capacity market, and therefore reduces the ORTP value.

For reasons that largely mirror those provided above in Section IX.A addressing NEPOOL's proposed Economic Life amendment, and the reasons provided above in Section IX.B.2.a on the application of the Economic Life amendment to the ORTP calculation for offshore wind, the ISO opposes the NEPOOL-supported photovoltaic solar ORTP value.

During stakeholder discussions of its proposed 30-year assumed project life for calculating the ORTP for photovoltaic solar, the proponent of the Economic Life proposal provided as support a second report from the Berkeley National Laboratory, this time summarizing the results of a recent survey of 19 solar industry professionals. The intent of the survey was "to clarify trends in the expected useful life and operational expenditure (OpEx) of

¹⁵¹ See CEA Report at 77.

¹⁵² The 2021 Appropriations Act also extended eligibility for a Production Tax Credit ("PTC"). However, the PTC is not available to facilities that begin construction after December 31, 2021. Accordingly, the PTC is not considered in the ORTP analysis.

¹⁵³ CEA ORTP Addendum at 5-6.

¹⁵⁴ CEA ORTP Addendum at 4.

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utility-scale photovoltaic (PV) plants in the United States."¹⁵⁵ According to the report, 17 out of the 19 professionals surveyed use 30 years or more for the useful life assumptions for solar facilities.¹⁵⁶

As with the report on the offshore wind survey, the ISO does not have reason to question the validity of the report, though it notes that a single survey of 19 professionals regarding assumptions about the useful life of solar projects is hardly concrete evidence of the actual useful lives of such facilities. This is, in part, the challenge that the ISO would face in attempting to implement such a provision, as there is little hard data available to support a specific value, in particular with respect to newer technologies such as large-scale photovoltaic solar projects.

However, even if the opinions of the 19 professionals are accurate, applying a 30 year "Economic Life" to the discounted cash flow analysis for the photovoltaic solar ORTP, without making other critical adjustments, introduces the same likely inaccuracies that were noted above with respect to the application of the Economic Life amendment to the offshore wind ORTP. First, the discounted cash flow analysis performed by NEPOOL appears to assume a 30-year debt term, without justification, an assumption that artificially lowers the ORTP for the photovoltaic solar technology. Second, it is not reasonable to assume a steady revenue stream for all 30 years (as the NEPOOL-proposed ORTP value appears to do), as declining project output due to performance degradation over time will reduce revenues in the latter years. Finally, it is equally not reasonable to assume no increase in maintenance or repair costs.

In summary, to accurately extend the financial time horizon for the discounted cash flow calculation for ORTPs requires making a number of decisions and adjustments to the calculation methodology. As with their offshore wind ORTP, none of these adjustments have been accounted for in NEPOOL's proposed 30-year discounted cash flow analysis for photovoltaic solar. Accordingly, the ISO opposes NEPOOL's proposed photovoltaic solar ORTP value.

D. Energy Storage Device – Lithium Ion Battery

As battery resources are increasingly deployed in New England, the ISO is including for the first time an ORTP for a lithium ion battery electric storage facility.¹⁵⁷ Concentric modeled a battery storage resource capable of delivering 150 MW of power at the point of interconnection, and storing 300 MWh of energy, a project size that is consistent with several larger battery storage projects proposed in the Forward Capacity Market queue and with data collected from

¹⁵⁵ See Asset Lifetimes for the ORTP Calculation: A Proposed Amendment, slide 6, presented to the NEPOOL Markets Committee on September 8-10, 2020, *available at* https://www.iso-ne.com/static-assets/documents/2020/09/a6_a_v_renew_amendment_asset_lifetime_for_ortp_calculation.pdf; citing Benchmarking Utility Scale PV Operational Expenses and Project Lifetimes: Results from a Survey of U.S. Solar Industry Professionals, Ryan Wiser, Mark Bolinger, and Joachim Seel, Lawrence Berkeley National Laboratory, June 2020 at 1, *available at* https://eta-publications.lbl.gov/sites/default/files/solar_life_and_opex_report.pdf.

¹⁵⁶ *Id*.

¹⁵⁷ Lithium ion technology was chosen because it is the most common battery type being installed in the United States, and there are multiple lithium ion battery electric storage facilities operating in the New England region. *See* CEA Report at 81-82.

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New England developers.¹⁵⁸ Concentric used a two-hour duration for the facility, consistent with projects that are focused on energy and ancillary services.¹⁵⁹ Additional details regarding the chosen facility are explained in the CEA Report.¹⁶⁰

NEPOOL supported an alternative ORTP value for an Energy Storage Device, which would reduce the ORTP for the technology from the ISO's proposed value of \$2.912/kW-month to the NEPOOL-supported value of \$2.601/kW-month, a difference of \$0.315/kW-month. The reduction in the ORTP for the NEPOOL alternative reflects the manner in which the resource is assumed to be dispatched for energy and ancillary services. The ISO modeled energy revenues for the battery storage facility to reflect infrequent cycling of the battery, only when real-time prices are relatively high. This modeling is consistent with observed behavior of battery storage resources in the ISO-administered markets to date.¹⁶¹ As the ISO understands it, the NEPOOL alternative uses a model that assumes storage resources will arbitrage in-day energy prices nearly daily, based on day-ahead market price patterns. This increases the dispatch frequency and the overall energy revenues, thereby reducing the ORTP modestly.

The ISO did not support the NEPOOL alternative for this technology largely because it is inconsistent with observed dispatch behavior of the commercial battery storage facilities operating in the ISO-administered markets to date; and, further, because the NEPOOL-supported alternative does not account for associated increased cell-augmentation (also called degradation) costs that would result from more frequent cycling.

However, the ISO does not disagree that the dispatch model in the NEPOOL alternative may well reflect a more optimal use of storage technologies, and that it is reasonable to assume storage providers will move in the direction of operating their resources in the most optimal manner they can identify going forward. Therefore, given the uncertainties regarding how these developing battery storage devices will participate in the market in the future, the ISO believes there is a range of reasonable values for the battery storage device ORTP. Further, the ISO considers the \$0.315/kw-month difference between the ISO and NEPOOL ORTP values to be within this range of reasonableness, given that the two values both reflect reasonable differences in assumptions about future battery dispatch patterns.

Accordingly, the ISO is not opposed to the Commission's adoption of the NEPOOL alternative ORTP value for the battery storage technology, should the Commission deem the NEPOOL alternative to be preferable.

¹⁵⁸ CEA Report at. 81-82.

¹⁵⁹ *Id*.

¹⁶⁰ *Id*.

¹⁶¹ Battery technology currently has very limited market representation, although the ISO has recently observed increased interest. As a result, the ISO uses its current observed participation here, but acknowledges that market participation could change in the future, considering the larger size modeled for the technology.

E. Modification to the Methodology for Calculating ORTPs for Resources Composed of Multiple Assets Having Different Technology Types

As explained above, if a new capacity resource is composed of multiple assets, and those assets have different technology types, the ORTP value is calculated using a weighted average formula as follows:

For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.¹⁶²

NEPOOL is proposing what it refers to as two clarifications to this methodology for calculating ORTPs for resources composed of multiple assets having different technology types. In a presentation to stakeholders from February 2021, the proponents of this "clarifying" Tariff amendment stated that:

The amendment will clarify existing Tariff language to even more definitively state that in assigning the Offer Review Trigger Price (ORTP) for FCA 16 the Internal Market Monitor (IMM) will, for

- Co-located assets of multiple technology types (e.g., PV + battery) registering as a <u>single</u> Forward Capacity Market (FCM) resource:
 - assign an ORTP equal to the weighted average of the ORTPs applicable to the asset(s) comprising the resource, as prescribed in Sections III.A.21.1.1 and III.A.21.2(c); and for
- Co-located assets of multiple technology types registering as <u>separate</u> FCM resources:
 - assign each FCM resource its own ORTP as applicable solely to the technology of the asset(s) underlying the resource.¹⁶³

To accomplish this clarification, NEPOOL proposes to add Tariff language that states: "Where one or more assets sharing a point of interconnection register as a New Capacity

¹⁶² Tariff Section III.A.21.2(c). Section III.A.21.1.1 also states in relevant part: "Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c)."

¹⁶³ See Amendment to the ORTP Calculation for Combined Resources for FCA 16, slide 3, presented to the NEPOOL Participants Committee on February 24, 2021, *available at* https://www.iso-ne.com/static-assets/documents/2021/02/a02 mc 2021 02 24 joint stakeholder amendment.pptx.

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Resource that does not include all of the assets sharing the point of interconnection, the Offer Review Trigger Price for the New Capacity Resource will be assigned according only to the asset or assets comprising the New Capacity Resource."¹⁶⁴

The ISO has not made a determination on whether it opposes NEPOOL's proposed Tariff amendment. By its terms, the amendment would appear to permit capacity suppliers with new resources to receive different ORTP treatment for the same physical combined resource simply based on the manner in which it registers the resource in the Forward Capacity Market. On its face, this "clarification" seems problematic, as registration alone, without an actual physical difference in the resource, is not a legitimate basis for permitting different ORTP treatments.

The ISO acknowledges, however, that this Tariff amendment was raised late in the stakeholder discussions, and that there was insufficient time to fully vet this amendment. Therefore, the ISO will provide additional information to the Commission regarding this NEPOOL-proposed Tariff amendment after reviewing NEPOOL's filed materials in this proceeding.

X. REVISIONS TO THE "INTERIM YEAR" INDEXING RULES

As explained above, pursuant to Section III.A.21.1.2(a), the ISO is required to perform a full recalculation of the ORTP values at least once every three years. Section III.A.21.1.2(e) specifies that, for years in which a full recalculation of the ORTP values is *not* being performed, the ISO is to make several adjustments to the ORTP values to be used in the upcoming FCA. These requirements are often referred to as the "indexing rules" or "interim update rules" for the ORTPs.

The ISO is proposing several modifications to the indexing rules. Several of these changes clarify certain aspects of the rules in response to questions or suggestions from stakeholders, and help to provide clearer guidance to the ISO and Market Participants on how the adjustment is to be performed. Others are more substantive additions or revisions, reflecting updates to federal tax laws that impact the capital costs for various technology types. Each change is addressed herein, with additional explanation and analysis provided for alternative changes proposed by NEPOOL.

A. Updates to Indices Used for Adjusting Capital and Fixed Operating Costs for Gas-Fired Resources

Section III.A.21.1.2(e)(1) and (2) of the Tariff require that, for an interim year adjustment, each capital cost in the capital budgeting model be updated to reflect changes in Bureau of Labor and Statistics Producer Price Indices since the ORTP recalculation was

¹⁶⁴ NEPOOL Proposed Amendment Tariff Revisions at Section III.A.21.1.1. The amendment also adds the clarifying example of a resource that is composed of multiple assets where the weighted average formula would be employed: "(including, but not limited to, a photovoltaic solar generator sharing a point of interconnection with an energy storage device participating in the energy market as one or more assets and participating in the capacity market as a single New Capacity Resource)." *Id.*

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performed. These provisions are being updated to identify that a single Producer Price Index the Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114)—will be used to update all capital cost adjustments for both simple cycle combustion turbines and combined cycle gas turbines. This index will also be used to update fixed operation and maintenance costs, and, therefore, sub-section (2), which addresses fixed operation and maintenance cost indexing separately, has been combined with sub-section (1), and the separate subsection (2) is being struck from Section III.A.21.1.2(e). These changes are intended to simplify the calculation and updating for inflation of the ORTP's capital and fixed costs for new gas-fired units, a change recommended by Concentric.¹⁶⁵

B. New Annual Cost Indices for Adjusting Capital and Fixed Operating Costs for Certain Renewable ORTP Technologies

For the remaining (*i.e.*, non-gas-fired) technology types (in Section III.A.21.1.2(e)(1)), the capital cost indexing rules are being updated to require that each ORTP be adjusted to reflect changes in the levelized cost of energy for that technology type, using Bloomberg cost of energy indices that are specific to the technology types. As noted by stakeholders during discussion of the ORTP updates, technology-specific indices such as those published by Bloomberg are better indicators of future changes in capital costs for non-gas-fired resources (better than available Bureau of Labor Statistics indices, which are not directly calculated for, or applicable to, many renewable energy technologies). These new indices more accurately reflect changes in costs for newer and emerging technologies, and appropriately reflect that, for many renewable resources, capital costs and fixed operating costs do not track closely with changes for gas-fired technologies.

C. Clarification of Electricity and Natural Gas Price Updates

Pursuant to Section III.A.21.1.2(e)(4) (now (e)(3)), the ISO uses electric and gas forward indices, as published by the Intercontinental Exchange (ICE), to update the energy and ancillary service revenue offsets as part of the interim updates. At the request of stakeholders, the ISO has added language to the Tariff specifying that the values published on the first five trading days of February will be captured and input into the capital budgeting model used to update the energy and ancillary services revenues. This specificity provides consistency and greater transparency to Market Participants regarding how and when the update will be performed. Further, Tariff language changes clarify that the index values used in the interim update will be those applicable to the months in the Capacity Commitment Period for which the update is being performed.

¹⁶⁵ CEA Report at 99 ("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. ")

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D. Clarification to REC Updates

The requirement in Section III.A.21.1.2(e)(5) (now (e)(4)) for updating Renewable Energy Certificate ("REC") values in the capital budgeting model is being modified to use an average of the five vintages (rather than a single vintage) closest to the first year of the relevant Capacity Commitment Period. Currently, the most recent Massachusetts Class 1 REC prices for the vintage closest to the first year of the relevant Capacity Commitment period are used to estimate REC revenues in the interim update process. For example, in the interim update performed for the 2024-2025 Capacity Commitment Period, the REC price published for the 2020 Index on February 14, 2020 (escalated to 2024\$) was used to calculate the assumed REC revenues.

Table 3 below lists the REC values used in the previous recalculation of the ORTP values in 2016, as well as the interim updates performed since, along with the onshore wind ORTP value. It is clear that the REC revenues fluctuate significantly between vintages, and these fluctuations can have a significant impact on ORTP values from year to year (although they are not the sole reason for fluctuations in each year).

Capacity Commitment Period	MA Class 1 REC Vintage Year	MA Class 1 REC Vintage Value	Offer Review Trigger Price – Onshore
		(\$/MWh)	Wind (\$/kW-mo)
2021-22	2017	\$26.50	\$11.025
2022-23	2017 ¹⁶⁶	\$26.53	\$8.472
2023-24	2019	\$11.83	\$13.099
2024-25	2020	\$39.46	\$0.000

Table 3: REC Values Used in ORTP Calculations

The proposed revisions replace the use of the single vintage with an average of the REC prices from the five vintages closest to the first year of the applicable Capacity Commitment Period to calculate the REC revenues in future interim updates. This change will render the update less susceptible to significant shifts from year-to-year, and therefore will reduce the year-over-year fluctuations in the ORTP values.

¹⁶⁶ Note that for 2022-23, the MA Class 1 REC Vintage Year was not updated, so that 2017 was used for a second year.

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E. Reductions in Bonus Tax Depreciation

The Tax Cuts and Jobs Act, enacted at the end of 2018, increased a particular tax-related accounting treatment, known as 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. The bonus depreciation adjustment is included in the financial model for the ORTPs, at a rate of 40 percent for the Capacity Commitment Period associated with FCA 16.¹⁶⁷ To reflect the decrease in the bonus depreciation adjustment for subsequent years, the ISO is including a new provision in the indexing rules, Section III.A.21.1.2(e)(5), to specify that the adjustment will be 20 percent for Capacity Commitment Periods associated with FCA 17, and zero thereafter. The adjustment to 20 percent for FCA 17 and zero thereafter reflects the recommendation of CEA, which took account of available guidance on the likely adjustments for these years.¹⁶⁸

An additional Tariff change in Section III.13.2.4 clarifies that the bonus depreciation adjustment referenced in Section III.A.21.1.2(e)(5) will not apply to the interim updates to CONE and Net CONE, which also employ the indexing rules in Section III.A.21.1.2 for interim year updates. As explained in the CEA Report, the bonus tax depreciation adjustment is not included in the CONE and Net CONE calculations.¹⁶⁹ The new clause in Section III.13.2.4 expressly recognizes the exclusion.

F. Revisions to the Federal Investment Tax Credit for Certain Renewable Energy Generation Technologies

As was addressed above, the 2021 Appropriations Act provides an extension of the beginning of construction deadline that must be met in order to qualify for the ITC for certain types of facilities. It is reasonable to assume that a developer of a facility that could qualify for the ITC would take steps to meet the specified construction deadlines in order to do so. For solar facilities, the ITC benefit decreases over time under the 2021 Appropriations Act. The ISO's and the NEPOOL-supported ORTP interim update rules differ with regard to which future ITC values solar photovoltaic facilities should be assumed to qualify for.

¹⁶⁷ CEA Report at 79. While an election to take advantage of bonus depreciation may not be feasible for every new entrant, it is reasonable to assume that some new entrants will be able to utilize the benefit 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. *See also PJM Interconnection, L.L.C.*, Order Accepting Proposed Tariff Revisions, 167 FERC ¶ 61,029, P 34 (April 15, 2019), finding, in the context of PJM's proposal to include bonus depreciation in cost of new entry reset, 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."

¹⁶⁸ CEA Report at 102 ("available guidance suggests that 20% bonus depreciation will be available for units placed in service in calendar year 2026 and will expire thereafter"). *See e.g.*, KPMG, Power and Utility Industry Measures in New Tax Law, p. 8, *available at* https://assets.kpmg/content/dam/kpmg/us/pdf/2018/01/tnf-power-utilities-new-law.pdf.

¹⁶⁹ See CEA Report at 79 (noting that while it reasonable to assume it for purposes of ORTP calculations, "the expected cash flows do not justify including it in the CONE analysis").

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By way of context, as discussed previously in Section VII, the ISO has accounted for the extension and assumed qualification for the ITC by photovoltaic solar facilities under development for FCA 16, in the calculation of ORTPs for FCA 16.¹⁷⁰ The ISO assumes that the solar technology will qualify for the higher ITC value under the "safe harbor" provisions, which allow commercial customers to preserve the tax credit of the current year by meeting the project cost (incurring 5% of the total project price) and continuity (completing construction within four years) criteria.¹⁷¹ These impacts are addressed in the CEA ORTP Addendum.¹⁷²

The difference at issue concerns what should be assumed in this regard for FCA 17 and FCA 18, as the ITC provisions applicable to photovoltaic solar "step down" under the Act. The following table summarizes the ITC rates based on the year that project construction begins. The ISO is assuming that construction for a facility that is to participate in FCA 16, to take place in February 2022, will not begin until *after* the facility participates in the auction. Therefore, for FCA 16, the ISO has accounted for a 26% ITC in calculating the ORTP for photovoltaic solar resources.

	1
Vear Construction Begins	ITC
I car construction Degins	110
2019	30%
2017	5070
2020	2 (0)
2020	26%
	-
2021	2(0/
2021	26%
2022	26%
2022	2070
2023	22%
2025	2270
After 2023	10%
111111 2020	1070

Fable 4 : ITC	Assumptions ¹	173
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Because the ITC steps down over time, a provision is being added, in a new sub-section (6) to Section III.A. 21.1.2(e), to account for the step-down of the ITC in the interim ORTP update for FCA 17 and beyond. For FCA 17, the ITC adjustment is reduced to 22 percent, to account for the reasonable assumption that resources participating in the February 2023 auction

¹⁷⁰ In order to qualify for the ITC, CEA extended the construction period for the solar resource from 16 to 30 months; the construction begin date is presumed to be in December 2022, for commercial operation by June 1, 2025.

¹⁷¹ For solar technology, this required an extension of the construction schedule from 16 months to 30 months.

¹⁷² CEA ORTP Addendum at 5-6. As CEA notes, the PTC is not available to facilities that begin construction after December 31, 2020. Accordingly, the PTC is not considered in the ORTP analysis.

¹⁷³ CEA ORTP Addendum at 6.

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will begin construction thereafter, and likely not before. For FCA 18 and beyond, the ITC adjustment is reduced to 10 percent, again accounting for the likely year construction will begin.

NEPOOL proposes an alternative to the ITC indexing provision in sub-section (6) to Section III.A.21.1.2(e) to require the use of 26 percent for the ITC in FCA 17 and 22 percent for the ITC in FCAs 18 and beyond. Thus, the NEPOOL alternative assumes that for FCA 17, a developer would begin construction on its facility in 2022, *before* the developer knows whether it will be receiving capacity revenues for its resource through participation in the February 2023 FCA. Specifically, to qualify for the 26% ITC for FCA 17 or 22% for FCA 18, a solar resource would need to extend its construction period to 42 months—almost three times the necessary and initially modeled construction period of 16 months—without certainty that the resource would receive a Capacity Supply Obligation from the applicable auction.

The ISO does not believe that the construction and development schedule underlying the NEPOOL-supported alternative ITC indexing proposal is reasonable. Specifically, it is not reasonable to assume a developer would put such a significant amount of capital at risk far before having the opportunity—much less an actual capacity supply obligation—to acquire some assurance of recovering those costs through participation in the FCM.

G. NEPOOL Amendment to Require Updates to Indexing to Account for Potential Future Changes to PTC and ITC Tax Laws

NEPOOL proposes to add to sub-section (6) of Section III.A.21.1.2(e) a requirement that, in the years when interim updates are performed, the ISO update the PTC and ITC adjustments to reflect any changes in the tax law that were not known at the time of this filing. This amendment would require that, prior to performing its indexing of the ORTP values for years in between the full ORTP updates, the ISO evaluate any changes to the tax law related to PTCs and ITCs, and reflect those changes in the interim update.

The ISO strongly opposes this amendment. Any such changes to the tax laws are potentially complicated, and subject to interpretation regarding their applicability, conditions, exclusions, and proper accounting in order to model their impact to the ORTP values—as we saw in the stakeholder process related to the most recent tax law change.¹⁷⁴ Addressing such potentially complex tax law changes requires a level of scrutiny and outside professional expertise that warrants review with stakeholders, consultations with outside specialists in Federal tax law, and even potentially subjective professional judgement about the appropriate

¹⁷⁴ The current disagreement between the ISO and NEPOOL over the application of the ITC and PTC during the indexing years is a case in point. As explained above, NEPOOL and the ISO have different interpretations of the ability of a resource developer to take advantage of the ITC in a given year. In addition, during the course of discussions of the application of the Consolidated Appropriations Act of 2021, stakeholders engaged independent tax experts to evaluate the ISO's proposed approach to reflect the updated ITC and PTC provisions on the ORTPs, a process that resulted in the ISO accepting some (but not all) of the tax expert's suggestions, and which required significant scrutiny on complex tax issues. Stakeholder engagements such as these, and the disagreement reflected in the NEPOOL amendment, are best addressed when the ISO is performing an update of the ORTP values for filing with the Commission, where such disagreements can be properly adjudicated by the Commission.

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applicability of ITC or related provisions.¹⁷⁵ All of this could possibly impact the ORTP values in a manner sufficient to warrant filing with the Commission. In that case, the ISO would perform an appropriate update to the ORTP values, not simply an indexing. Such actions are not consistent with the intended automatic nature of the interim-year indexing updates, but rather are best addressed when the ORTP receives a full update at least once every three years.

XI. STAKEHOLDER PROCESS

The ORTP updates filed here were considered through the complete NEPOOL Participant Processes. The ISO, its consultants, and stakeholders discussed the various FCM parameter updates in 12 separate meetings of the NEPOOL Markets Committee. These meetings, many of which spread across two or even three days, started in May 2020 and finished in March 2021.

The ISO and its consultants also held numerous meetings and telephone calls with stakeholders outside of the NEPOOL process over this period to solicit feedback, address specific concerns and evaluate stakeholder amendments.

Throughout this process, the ISO listened to stakeholder feedback on a range of issues, and the ISO made modifications to several of its proposals to address their concerns. For example:

- The ISO accounted for stakeholders' "on-the-ground" experience with respect to several aspects of the ORTP calculations, including, as an example, information from current battery storage providers that informed assumptions about market participation, leasing rates and plot size.
- In response to questions and comments from Market Participants regarding offshore wind capital costs, ISO-NE worked with its consultants to ensure the costs reflected the lower end of the competitive range, decreasing estimated capital costs by approximately 9%.¹⁷⁶
- The ISO also worked with stakeholders to ensure that the interim update process (used during years when a full ORTP update is not performed) appropriately accommodates the new technologies for which ORTPs were developed. In response to stakeholder input regarding the index proposed for updating capital costs for renewable technologies, the ISO modified its proposal to use indices specific to the technology type. Further, the ISO revised the calculation of RECs

¹⁷⁵ This can arise, for example, because recently enacted legislation may not yet be supplemented with Internal Revenue Service regulations or may otherwise lack the fulsome guidance of the Internal Revenue Service on how tax legislation should be applied to specific technologies, financing arrangements, and other tax-accounting conditions.

¹⁷⁶ This effort resulted in Mott MacDonald choosing lower cost options for a number of aspects of the capital cost estimation, including the method for laying the undersea cables and the determination of the project contingency value. *See* Mott MacDonald Report at 3, 14 and 15.

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> used in the interim update process from a single index to an average of indices to reduce the year-to-year variability, in the resulting ORTP values; and included in Tariff revisions the publication date for the values used to improve transparency for stakeholders.

The ISO and its consultants also spent considerable time working with NEPOOL stakeholders on their various amendments. This included verifying the underlying calculations for their proposals and providing guidance on how to adjust CEA's discounted cash flow model to reflect stakeholder proposals (for example, the Economic Life proposal). As part of this engagement, the ISO made its consultants available to stakeholders to thoroughly review stakeholder proposals, which produced valuable modifications and corrections that improved the overall quality of stakeholder proposals.

In short, the ISO worked diligently throughout the stakeholder process to explain its proposal, answer stakeholder questions, find resolution on differences, and support stakeholder development of their own proposals.

NEPOOL ultimately voted not to support the ISO's proposed ORTP values and its related Tariff revisions. NEPOOL instead voted to support a package of ORTP values and Tariff revisions that reflected various proposals that stakeholders had developed. The details of these votes are contained in NEPOOL's filing materials in this proceeding.

XII. 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.¹⁷⁷ 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;
- 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");
- 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

¹⁷⁷ 18 C.F.R. § 35.13 (2016).

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Capacity Auction; FCA 16 and Forward, Addendum – CONE/Net CONE, March 2021 (referred to herein as the "CEA CONE Addendum");

- 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, Addendum ORTP, April 2021 (referred to herein as the "CEA CONE Addendum");
- Direct Testimony of Danielle S. Powers, Concentric Energy Advisors, Inc. and Attachment DSP-1 on Behalf of ISO New England (referred to herein as the "Powers Testimony");
- *Mott MacDonald Offshore Wind ORTP Report* (referred to herein as the "Mott MacDonald Report");
- Affidavit of Danielle S. Powers, Concentric Energy Advisors, Inc.;
- Affidavit of Keith Paul, Mott MacDonald, Inc.;
- Blacklined Tariff sections reflecting the ISO-NE revisions discussed in this filing;
- Clean Tariff sections reflecting the ISO-NE 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 Section II above, the ISO requests that the Tariff revisions filed herein become effective on June 8, 2021.

<u>35.13(b)(3)</u> – 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.isone.com/participate/participant-asset-listings. A copy of this transmittal letter and the accompanying materials has 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 Section XII of this transmittal letter.

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35.13(b)(5) – The reasons for this filing are discussed in Sections I and VI-VIII of this transmittal letter.

<u>35.13(b)(6)</u> – 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.

XIII. CONCLUSION

For the reasons discussed in this transmittal letter, the ISO requests that the Commission accept the updated FCA 16 ORTP values and the associated Tariff revisions as filed herein, as the just and reasonable and preferable set of Tariff revisions before the Commission in this proceeding, to become effective on June 8, 2021.

Respectfully submitted,

ISO NEW ENGLAND INC.

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Counsel for ISO New England Inc.

Attachment I-1b

December 2020 CONE and ORTP Report

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 M MOTT MACDONALD

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 breakeven 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.

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 gasfired resources in New England and the participation of these resources in recent FCAs. The results of our CONE analysis are shown below.

	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

Table 1: Net CONE Values for Candidate Reference Units

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.

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-m0)	\$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

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

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 \P 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.

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

Table 3: Application of CONE Analysis Criteria

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.

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).

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 Announc ed	MA	64	Late Stage Development	N/A
West Medway II	Gas Turbine	2019	GE Energy	LMS100P A+	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

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

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.

	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	\checkmark	\checkmark	\times
Offshore Wind	\times	\checkmark	×
Coal/Nuclear	\times	\checkmark	\checkmark
Solar	\times	\checkmark	\times
Large-Scale Battery	\times	\times	\times

Table 5: Resource Screening Results

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.

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 M501 JAC 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 501 JAC	 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

Table 6: Simple Cycle Frame Machines

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.

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

 Table 7: Simple Cycle Aeroderivative Machines

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.

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 7FA04 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 M501 JAC. 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	 M501 J is a steam cooled large frame gas turbine Slightly lower capacity than the M501 JAC Classic, but with equal heat rate

Table 8: Combined Cycle Combustion Turbines

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.

Key Assumptions				
KET ASSOMETIONS				
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			

Table 9: Key Assumptions for Gas Candidate Reference Units

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 Risk¹⁰

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.

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

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.

Plant Name	Түре	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	СС	2018	805	Gas/ Distillate Fuel oil	GE Energy	7HA.01
Footprint Power Salem Harbor	CC	2018	674	Gas	GE Energy	7F.05

Table 10: Recent Gas Projects Developed in New England¹³

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 database¹⁴ 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 Category¹⁵

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.

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)	Shoulder: 9,132		
HHV	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.			

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

 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.

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)	Shoulder: 9,656
HHV	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 and August; Winter months are Dec Shoulder months are all other month	rate assumptions, Summer months are June, July, ember, January, February, and March; and ns.

Table 12: LM6000PF+ Technical Specifications

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.

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	Nominal: 544
(MW)	Summer: 526
	Winter: 570
Location	New London County, Connecticut
Cooling System	Fin fan coolers
Power Augmentation	Evaporative coolers
Baseload Net Heat Rate	Shoulder: 6,394
(Btu/kWh) HHV	Summer: 6,573
	Winter: 6,429
Duct Firing Net Heat Rate	Shoulder: 6,480
(Btu/kWh) HHV	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 a months are December, January, February,	ssumptions, Summer months are June, July, and August; Winter and March; and Shoulder months are all other months.

Table 13: GE7HA.02 Combined Cycle Technical Specifications

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

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	<u>10.4</u>
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)	<u>2.3</u>
Total Non-EPC	60.8
Total Overnight Capital Costs	288.0
\$/KW (Installed Capacity)	776.9

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

²³ Numbers may reflect rounding.

ii. LM6000PF+ Aeroderivative Gas Turbine

	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	<u>6.1</u>
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)	<u>1.3</u>
Total Non-EPC	53.2
Total Overnight Capital Costs	187.0
\$/KW (Installed Capacity)	1,961.4

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

²⁴ Ibid.

iii. 7HA.02 Combined Cycle Combustion Turbine

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	<u>20.9</u>
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)	<u>4.6</u>
Total Non-EPC	79.3
Total Overnight Capital Costs	535.3
\$/KW (Installed Capacity)	985.0

Table	16: 7HA	.02 C	Combined	Cycle	Capital	Costs	(2019\$,	in millions	5) 25
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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.

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

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

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.

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%

Table 19: Municipal Tax Rates for Towns in New London County²⁶

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

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	2.90%	2.82%	2.80%
Stonington			
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	2.9 1%	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

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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. $^{\rm 28}$

 $^{^{28}\;}$ 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, "nonrecourse" 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 surveybased 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 <u>https://www.clevelandfed.org/our-research/indicators-and-data/inflation-expectations.aspx</u>.

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-AE02020&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.

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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: <u>https://portal.ct.gov/DRS/Corporation-</u> <u>Tax/Tax- Information</u>.

- 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).

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	f June 30, 2020			
[2] Value Line as of	June 2020			
[3] Bloomberg data end debt %	as of June 30, 2020; I	D/E ratio is calculated	l from 2018Q2-2020	Q1 average quarter-

Table 20: Peer Group Beta Estimates

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.

CAPM										
		[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
	Risk Free						Market Ris	k Premium	ROE Bo	ised On
	Rate	B	Seta- Relevered	d	Historical	S&P 500			Historical	Projected
		Value Line	Bloomberg	Average	Return	Projected	Historical	Projected	м	RP
	<u>30-year</u> [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 %
	<u>30-year</u> [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%
	<u>30-year</u> [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%

Table 21: CAPM Results

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CAPM									
<u>Notes:</u>									
[1]									
a) 30-day c Bloomberg	average 30-Yr	T Note							
b) 10-year June 1, 202	forecast of 30- 0.	year Treasury	Bonds; Blue Cł	nip Financial F	orecast, Vol. 3	9, No. 6,			
c) Average June 1, 202	e 30-year treas 20.	ury yield for 20	026-2030; Blue	Chip Financia	l Forecast, Vol	. 39, No. 6,			
[2] Source: 7/24/20	Value Line ac	cessed on							
[3] Source:	Bloomberg Pre	ofessional as c	of 6/30/20						
[4] Equals c [3])	average ([2],								
[5] https://vaso r.pdf	dc8grscoc.blo	b.core.windov	ws.net/files/Re	leaseLogs/TEN	/PLATE_Navigo	atorReleaseUp	odate_Maste		
[6] Source:	Bloomberg Pre	ofessional							
[7] Equals [5] – [1]								
[8] Equals [6] – [1]								
[10] Equals [7])	[1] + ([4] x							(TRIC VISORS
[10] Equals [8])	[1] + ([4] x								

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.

	RISK FREE	ROE BASED ON			
	RATE	Historical	Projected		
		М	RP		
	<u>30-year</u>				
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%		
	<u> 30-year</u>				
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%		
	<u>30-year</u>				
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 22: CAPM Results – Sensitivity #1

Table 23: CAPM Results – Sensitivity #2

	RISK FREE	ROE BASED ON				
	RATE	Historical	Projected			
		М	RP			
	<u>30-year</u>					
NRG	1.47%	9.53%	14.88%			
VST	1.47%	11.14%	17.55%			
		10.33%	16.21%			
	<u>30-year</u>					
NRG	3.00%	9.31%	14.65%			
VST	3.00%	10.56%	16.97%			
		9.94%	15.81%			
	<u>30-year</u>					
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%.





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; <u>https://fred.stlouisfed.org/series/BAMLH0A2HYB[B]EY</u>.

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.

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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.

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

Table 24 : Recent IPP Debt Issuances⁴²

 $^{^{\}rm 42}~$ 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 Weights⁴³

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.

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%

Table 25: Total Debt/Total Capitalization44

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:

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.

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	ISO-NE ⁴⁵ (2014)	PJM ⁴⁶ (2014)	NYISO ⁴⁷ (2016)	ISO-NE ⁴⁸ (2016)	PJM⁴ ⁹ (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%

Table 26: Cost of Capital Comparison

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 PJM⁵⁰.

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.

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 SCAR	CITY ADJUSTED	PRICES						
Date	Hour End	Energy, Adj. Real- time LMP	RESERVE SCAR ADJ. REAL- TIME TMSR PRICE	CITY ADJUSTED ADJ. REAL- TIME TMNSR PRICE	PRICES ADJ. REAL- TIME TMOR PRICE						
DATE	Hour End	ENERGY, ADJ. REAL- TIME LMP 357.69	RESERVE SCAR ADJ. REAL- TIME TMSR PRICE 315.27	CITY ADJUSTED ADJ. REAL- TIME TMNSR PRICE 311.11	PRICES ADJ. REAL- TIME TMOR PRICE 173.81	_					
DATE 10/18/2017 10/22/2017	Hour END 19 19	ENERGY, ADJ. REAL- TIME LMP 357.69 172.60	RESERVE SCAR ADJ. REAL- TIME TMSR PRICE 315.27 146.08	CITY ADJUSTED ADJ. REAL- TIME TMNSR PRICE 311.11 145.49	PRICES ADJ. REAL- TIME TMOR PRICE 173.81 140.82						
DATE 10/18/2017 10/22/2017 9/3/2018	HOUR END 19 19 16	ENERGY, ADJ. REAL- TIME LMP 357.69 172.60 229.53	Adj. Real- TIME TMSR PRICE 315.27 146.08 147.22	CITY ADJUSTED ADJ. REAL- TIME TMNSR PRICE 311.11 145.49 147.22	PRICES ADJ. REAL- TIME TMOR PRICE 173.81 140.82 144.18						
DATE DATE 10/18/2017 10/22/2017 9/3/2018 9/3/2018	HOUR END 19 19 16 17	ENERGY, ADJ. REAL- TIME LMP 357.69 172.60 229.53 92.46	ADJ. REAL- TIME TMSR PRICE 315.27 146.08 147.22 61.57	CITY ADJUSTED ADJ. REAL- TIME TMNSR PRICE 311.11 145.49 147.22 61.57	PRICES ADJ. REAL- TIME TMOR PRICE 173.81 140.82 144.18 0.00						
DATE DATE 10/18/2017 10/22/2017 9/3/2018 9/3/2018 9/3/2018	HOUR END 19 19 16 17 18	ENERGY, ADJ. REAL- TIME LMP 357.69 172.60 229.53 92.46 375.72	RESERVE SCAR ADJ. REAL- TIME TMSR PRICE 315.27 146.08 147.22 61.57 313.30	CITY ADJUSTED ADJ. REAL- TIME TMNSR PRICE 311.11 145.49 147.22 61.57 313.30	PRICES ADJ. REAL- TIME TMOR PRICE 173.81 140.82 144.18 0.00 0.00						

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

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 atcriterion 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.

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

Table 28: Energy Market Scarcity Revenue

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).

2017	Jan	Feb	MAR	APR	ΜΑΥ	Jun	Jul	AUG	Sept	Ост	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	29:	Level	of	Excess	Ad	justment	Factors ⁵²
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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.

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.				

Table 30: Level of Excess Adjustment Example

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.

Candidate Reference	Day- Ahead	Real-Time Energy	Forv Reserve	WARD MARKET	R	REAL-TIME ESERVE MAR	KET
Unit	ENERGY		TMNSR	TMOR	TMSR	TMNSR	TMOR
Simple cycle	•	•	•	•		•	•
Aeroderivative	•	•	•	•		•	•
Combined cycle	٠	•			•		

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

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 Table 32.⁵⁴

	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%

Table 32: Lifecycle Degradation for CONE Units

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 offline 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 CO₂ and SO₂ 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.

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.

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

Table 33: Intraday Gas Premiums

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:

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

Table 34 : Reserves Amounts Provided (Shoulder Months)

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 <u>https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/fwd-cap-daily-threshold-price</u>.

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

Cost Assumptions

- Next-day gas price at Algonquin City Gates
- RGGI prices
- SO₂ prices

Unit Characteristics

- Size, heat rate, VOM, emissions, and \$11,000 startup cost
- Physical characteristics: 2hour minimum run time, quick start capability
- Duct-firing capability can provide synchronized reserves

Economic Offer Price

- Two offer blocks
 - Block 1: baseload capacity (MW total)Block 2: Duct firing (MW total)
- If offline, dispatch considers amortized startup cost and energy costs over its 2-hour minimum run time
- If online, dispatch only considers incremental production costs



Market Offer Price

- Offer Price = economic offer
- Offer price is the same in day-ahead and real-time markets
- Day-ahead award is a financial position
- Combined cycle does not participate in the FRM

Day-Ahead Market

Energy and Real-time Reserve market compensation

- Clear for energy if DA Offer ≤ Day-ahead LMP adjusted for LOE and scarcity. Financial position where revenues = DA 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

Real-time Market

- If RT Offer block ≤ Real-time LMP:
 - If block 1 clears for energy, the 2nd block is designated as TMSR
 - If block 1 and block 2 both clear for energy, the unit cannot provide TMSR
- If RT Offer > Real-time LMP:
 - Does not clear for energy
 - Is not designated for TMSR

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 <u>https://www.iso-ne.com/static-assets/documents/2020/10/a00 iso presentation scarcity hours and balancing ratios.pptx.</u>

\$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.

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

Table 35: Pay for Performance Assumptions

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
	Insta	LLED 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.

	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

Table 37: Net CONE Summary for Candidate Reference Technologies

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 "bottomup" 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.

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

Table 38: Resource Screening Results

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. <u>https://www.eia.gov/outlooks/aeo/assumptions/pdf/table 8.2.pdf</u>

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.

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%

Table 39: ORTP Financial Assumptions

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.

⁷⁵ Internal Revenue Service, Notice 2018-59. Available at: <u>https://www.irs.gov/pub/irs-drop/n-18-59.pdf</u>.

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.

	сс	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

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

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.

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

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

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.

	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

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

	ONSHORE WIND (ORTP)
Project Contingency	8.0
Owners Development Costs	<u>0.3</u>
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)	<u>1.2</u>
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.

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	<u>1.0</u>
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)	<u>1.3</u>
Total Non-EPC	11.9
Total Overnight Capital Costs	140.7
\$/KW	938

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

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.

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

 Table 44 : ORTP Energy/Reserve Scarcity Adjustment

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 summer scarcity hours are assumed to occur in the summer, transient scarcity hours are assumed to accur randomly through the year. 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 dayahead 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

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.

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. <u>http://www.caiso.com/InitiativeDocuments/FinalProposal-EnergyStorage-DistributedEnergyResourcesPhase4.pdf</u>.

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).

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

	Соѕт (2025\$/кw-мо)
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.

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	

Table 47: DR ORTP Calculation

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.

CONNECTICUT	MASSACHUSETTS	MAINE	New HAMPSHIRE	R HODE 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	

Table 48: Energy Efficiency Programs Included in ORTP Analysis⁸⁶

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 of 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.

		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

Table 49: Energy Efficiency Programs Costs

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

:		
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

Table 50: Energy Efficiency Programs Benefits

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.

Reference Technology	Nominal Installed Capacity (MW)	QUALIFIED CAPACITY (MW)	Installed Cost 2019\$/kW	REAL ATWACC	Gross CONE (2025\$/ĸW- MO)	Revenue Offsets (2025\$/kW- MO)	NET CONE (2025\$/kW- MO INSTALLED)	NET CONE (2025\$/KW- MO QUALIFIED)	О RTP (2025\$/кW- мо)
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

Table 52: Summary of ORTP Values

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.

	а	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

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

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.

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	<u>\$0.3</u>
	\$5.0
Permitting	\$1.5
Legal	\$2.5
Siting	\$1.0

Attachment I-1c

March 2021 CONE Report Addendum

ISO-NE NET CONE AND ORTP ANALYSIS

AN EVALUATION OF THE NET COST OF NEW ENTRY PARAMETER TO BE USED IN THE FORWARD CAPACITY AUCTION

FCA-16 AND FORWARD

ADDENDUM – CONE/NET CONE

MARCH 2021

CONCENTRIC ENERGY ADVISORS, INC.

MOTT MACDONALD





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SECTION 1: SUMMARY

A. Overview

ISO-NE engaged Concentric Energy Advisors, Inc. (Concentric) to conduct an independent analysis of the Cost of New Entry (CONE)/Net CONE and Offer Review Trigger Price values for the sixteenth Forward Capacity Auction (FCA 16). Concentric and its subcontractor, Mott MacDonald, worked together to develop the recommendations presented in a report finalized in December 2020 (December Report).

This Addendum is provided as a supplement to the original December Report that explains Concentric's CONE/Net CONE Study process, analysis, and findings. This Addendum includes revised CONE, Net CONE and Performance Payment Rate (PPR) values that reflect the correction of inconsistencies in applying the screening criteria for the reference unit. The December Report incorrectly stated that a hypothetical reference unit could be sited within two miles of a gas transmission mainline and 345 kV electric transmission network in New London County, Connecticut. This Addendum revises the hypothetical reference unit location to Tolland County, Connecticut.

The reference unit hypothetically could be sited in multiple locations that are within two miles of a gas transmission mainline and 345 kV electric transmission network in Tolland County, Connecticut. However, consistent with the approach in prior CONE Studies approved by the Federal Energy Regulatory Commission (FERC) in New England, as well as studies in New York and PJM, Concentric did not conduct a full engineering study for a specific site, nor did it conduct a detailed site feasibility analysis for the location of an actual proposed new generation project.

B. Summary of Recommendations

Based on our analysis, we recommend the following gross CONE and Net CONE values shown in Table 1.

	1x0 7HA.02 (CT)
NOMINAL INSTALLED CAPACITY (MW)	371
QUALIFIED CAPACITY	356 ¹
Installed Cost (2019\$/kW)	777
REAL ATWACC	6.1%
GROSS CONE (2025\$/kW-MONTH) INSTALLED	\$11.499
GROSS CONE (2025\$/KW-MONTH) QUALIFIED	\$11.978
Revenue Offsets (2025\$/kW-month)	\$4.669
NET CONE (2025\$/kW-MONTH) INSTALLED	\$6.829
NET CONE (2025\$/KW-MONTH) QUALIFIED	\$7.114

Table 1: Net CONE Reference Unit Summary (2025\$)

Note that the December 2020 Report stated a Qualified Capacity value of 361 MW on Pages 10 and 73. This value represents the qualified capacity percentage of 96% applied to the installed capacity value of 376MW before degradation. The December 2020 Discounted Cash Flow Model uses the post-degradation Qualified Capacity Value of 356 MW. This value represents the installed capacity of 376 MW adjusted for degradation (1.41% degradation of 376 MW = nominal installed capacity of 371 MW) and adjusted for the qualified capacity percentage (96% of 371 = 356 MW).

SECTION 2: NET CONE STUDY – REVISED REFERENCE UNIT LOCATION

A. Reference Unit Location

In response to a FERC Deficiency Notice issued on March 1, 2021,² ISO-NE requested that Concentric identify an example of a potential site for the Net CONE reference unit in or near New London County, Connecticut, that is two miles from both a main natural gas transmission line and the point of interconnection to the electric grid.

In order to provide an example of such a site, we reviewed natural gas and electric infrastructure within two miles of the gas and electric grids in New London County, Tolland County, and Windham County, Connecticut. In the course of this analysis, we determined that a potential site meeting the specified criteria should be located in Tolland County. More specifically, CEA identified available greenspace within Tolland County that is within two miles of both the Algonquin gas transmission mainline and the 345 kV electric transmission line.

In order to reconcile the location criteria for a two-mile interconnection³ to the Algonquin gas transmission mainline and the 345 kV electric transmission line, Concentric recommends adjusting the reference unit location from New London County to Tolland County, Connecticut. The location of the unit in Tolland meets the key location criteria, and therefore would enable the reference unit to connect to both the gas mainline and the 345 kV transmission grid. The map attached hereto as Exhibit A identifies a location of approximately 230 acres that meets these criteria, including the necessary acreage for siting the reference unit (eight acres).⁴ The map attached hereto as Exhibit B identifies numerous eight-acre parcels within the 230-acre location where the reference unit hypothetically could be sited.

² Deficiency Notice, FERC Docket 21-787-000 (March 1, 2021).

³ Mott MacDonald estimated interconnection costs using its proprietary data regarding many projects throughout the United States and multiple pipeline projects in the New England, New York, and PJM areas. A survey of sixteen projects in its database resulted in a range of \$3.2-\$5.1 million per mile for gas interconnection. Several of these pipeline projects are long pipelines with multiple expensive crossings, and some traverse expensive developed areas, driving costs up to the higher end of the range. Using data from projects of a similar length to the reference facility here, with few expensive crossings, the costs assumed fell in the middle of this range, at \$4.5 million per mile, which is reasonable for a two-mile lateral.

⁴ The required site acreage for the reference unit is noted in the December Report, p. 33 Table 11. While some of the area identified on the maps shown in Exhibits A and B are within a floodplain, the identified area is 230 acres in size, while the reference unit requires a site size of approximately eight acres. There are many possible Tolland County locations both within the identified area and outside the identified area where the unit could be located within two miles of electric and gas transmission. Further, not all the identified sites in Exhibit B are within the floodplain. Concentric assumes a developer would consider the many factors that may impact siting costs, including floodplain, when choosing a location for the site, and would choose the site that improves the overall competitiveness of the unit.

B. Evaluation of Impact of Change in Location on Inputs into CONE Calculations

Because of the resulting change in the general location from New London County to Tolland County, Concentric performed an assessment of the inputs into the CONE/Net CONE calculation to determine which inputs may be impacted by the change in the reference unit's location. Concentric evaluated each location-related input to the December Report and determined that only one financial input, the assumed property tax rate, required adjustment to reflect the change to Tolland County.⁵ To determine the impact of the change in the property tax rate, consistent with the approach to determine the property tax rate as described in the December Report, Concentric estimated property taxes by reviewing all available mill rates for municipalities within the proposed county for years 2018 - 2020. The original property tax rate for New London County included 21 cities and towns, with a three-year average mill rate of 2.89%. The revised property tax rate for Tolland County is based on 13 cities and towns, with a three-year average mill rate of 3.32%. The resulting impact to Net CONE, factoring in the impact to the PPR,⁶ is approximately \$0.090/kW-mo.

No other components of the estimate were impacted as a result of this location change. A summary of the Concentric and Mott MacDonald analysis on these points is below. We note that the estimates have consistently allowed for reasonable costs for particular categories, rather than cost estimates derived from a detailed scope of work for a specific, potentially unique candidate site parcel. These assumptions are, and are intended to be, generalized assumptions for the reference unit, not specific to a particular plant, project developer, construction contract or parcel of land.

Costs Evaluated	POTENTIAL LOCATION IMPACT	IMPACT DETERMINATION AND EXPLANATION
Balance of Plant Materials	As noted in the December Report (pg. 27), these materials were adjusted "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."	No cost adjustment needed. No construction material adjustments are needed due to the close proximity of the newly proposed county location which is adjacent to New London County.
Construction Labor	Construction labor rates were based on union labor rates for the New London County, Connecticut area.	No cost adjustment needed. Mott MacDonald reviewed union wage rates in ten locations throughout Connecticut in 2019. No county-specific adjustment is needed

Table 2: Review of Location Impact on Other Components of Net CONE Analysis

⁵ Concentric previously identified sites near Franklin, Connecticut, in New London County, as examples of land where the reference unit could potentially be built. For perspective, the Tolland County area identified on the map in Exhibit A is approximately 15 miles from the sites identified near Franklin.

⁶ The PPR will change from \$8,782 to \$8,894/MWh as a result of the change to the property tax rate.

Costs Evaluated	POTENTIAL LOCATION IMPACT	IMPACT DETERMINATION AND EXPLANATION
Construction Labor	Field labor productivity was based on field construction labor conditions for the New London County, Connecticut area.	No cost adjustment needed. Mott MacDonald reviewed labor conditions throughout Connecticut. No county- specific adjustment is needed
Direct Costs (Major Equipment, Installation, Labor)	Labor hours were adjusted to reflect the anticipated productivity levels associated with labor in the New London County, Connecticut area.	No cost adjustment needed. As noted above, no county- specific adjustment was necessary for wage rates.
Site Work	Site is anticipated to require a minimal amount of additional fill.	No cost adjustment needed. The same site work assumption applies to sites in Tolland County.
EPC Costs: Concrete Masonry Structural Steel/Metals Buildings Piping/Mechanical Electrical Instrumentation	Inputs to these costs include construction labor hours, field labor hours, and labor productivity.	No cost adjustment needed. As noted in Construction Labor above, labor wages rates in various locations throughout Connecticut were reviewed.
Indirect EPC: Construction Management Construction Equipment and Operators Indirect Construction Services and Support	Inputs to these costs include the inclusion of labor costs.	No cost adjustment needed. No change to labor costs; costs stay the same as noted above.
EPC Contractor Contingency	Evaluated as these costs are based on project EPC costs.	No cost adjustment needed. EPC costs are not dependent on county location, and therefore, this contingency would not change.
EPC Contractor Profit	Evaluated as these costs are based on total value of the project for EPC contractor.	No cost adjustment needed. EPC costs are not dependent on county location, and therefore, this contingency would not change.
Fixed O&M Costs	Evaluated as LTSA covers labor costs	No cost adjustment needed. As noted above, labor wage rates in various locations throughout Connecticut were reviewed.
Property Taxes	Property taxes were modeled for New London County.	Cost adjustment is required. Property taxes should reflect rates of Tolland County.
Site Leasing Costs	Evaluated for potential difference in leasing costs between New London and Tolland counties.	No cost adjustment needed. Site leasing cost benchmarking is generic based on the technology type and consistent with or similar to assumptions in past CONE studies.
Insurance	Insurance is based on total capital costs.	No cost adjustment needed. Insurance rate is assumed as a percentage of capital costs and is generic, and consistent with assumptions in past CONE studies.

Costs Evaluated	POTENTIAL LOCATION IMPACT	IMPACT DETERMINATION AND EXPLANATION
Change in Elevation and Average Temperature	Elevation and ambient temperature can impact turbine output.	No cost adjustment needed. The difference in average elevation and temperature between New London and Tolland County is de minimus.

Because of the change in property taxes, the CONE value for the reference unit was updated from \$11.399/kW-mo to \$11.499/kW-mo (based on installed capacity). This approximately \$0.10/kW-mo. change has a resulting impact on the estimated PPR, the calculation of which requires CONE as an input. PPR will change from \$8,782 to \$8,894/MWh. The offsetting effect of the PPR update is approximately \$0.01/kW-mo., which impacts the associated update to Net CONE. After accounting for the revised PPR value, the new recommended value of Net CONE, on a qualified capacity basis, is \$7.114/kW-mo.

SECTION 3: ACCESS TO SUFFICIENT GAS FOR REFERENCE UNIT TO RUN AS MODELED

Concentric is providing the following information in response to Question 1.b of the Commission's March 1, 2021 Deficiency Notice, and specifically in response to the question requesting that the ISO "explain how the reference unit would have access to sufficient natural gas to run as modeled."

The availability of sufficient natural gas for the reference unit to run as modeled is a function of two factors. First, the Algonquin mainline must have sufficient operating pressure so that gas can be delivered to the reference unit in sufficient quantities for it to operate at full capacity. Second, gas must be available at prices that would support the economic operation of the reference unit in the hours it is modeled to operate. These points are addressed in turn in the remainder of this section.

The modeling of the reference unit assumes it will offer its full capacity into the day-ahead and realtime energy markets. The pressure required for the GE 7HA.02 reference unit to operate at full capacity in the winter, and marginally lower in the summer, is 507 psig.⁷ Enbridge, the Algonquin pipeline operator, has confirmed that the Algonquin gas transmission mainline operating pressure of 750 psig in the general area proposed for the reference unit, well above the pressure required.⁸ While the pressure at a specific location on the pipeline is generally confidential, public documentation for an existing, comparable gas unit in Connecticut, located on the Algonquin W System, indicates the unit receives average pressure is at least 550 to 600 psig.⁹ Lateral pipelines that feed from the mainline generally operate at pressures that are lower than (or at least not higher than) the operating pressure of the mainline. Thus, it is not unreasonable to assume that the average pressure on the mainline would be at least this high if not higher, which is more than sufficient to support the operation of the reference unit at full capacity at the required pressure of 507 psig.

Further, a proposed 550 megawatt dual-fueled combined cycle electric generating facility in eastern Connecticut – Killingly Energy Center (KEC) – plans to connect to the main Algonquin transmission pipeline and is expected to have an operating pressure of approximately 600 psig¹⁰ and a maximum available operating pressure of 850psig.¹¹ This observation further supports the conclusion that

⁷ Concentric's consultant, Mott MacDonald, confirmed with GE representatives that the GE 7HA.02 unit can run at capacity if gas to the plant is at a pressure of at least 507 psig, based on an average winter ambient temperature of 13F and elevation of 250 FASL. *See* Exhibit C, email correspondence between Mott MacDonald and GE, confirming associated gas pressure requirements.

⁸ This information was conveyed from Enbridge to Concentric in a telephone call on October 19, 2020.

⁹ See Connecticut Siting Council, Petition 968, Staff Report (November 2010), available at <u>https://portal.ct.gov/-/media/CSC/3 Petitions-medialibrary/petition staff reports MediaLibrary/P968SRdoc.doc</u> ("The typical operating pressure would be on the order of 550 to 600 pounds per square inch gauge (psig), but will not exceed 750 psig.") Note that this Petition is from 2010, and the figure cited does not take the recent Algonquin Incremental Market expansion into account.

See Connecticut Siting Council, Docket No. 470B, Final Decision, Opinion and Order, Finding of Fact 177 (June 7, 2019), available at <u>https://portal.ct.gov/-/media/CSC/1_Dockets-</u> medialibrary/Docket 470B/FINALDECISIONDOCS/do470bcertpackage20190607pdf.pdf.

See Connecticut Public Utilities Regulatory Authority, Docket 20-06-22, Final Decision, p. 12, (January 13, 2021) available at http://www.dpuc.state.ct.us/dockhistpost2000.nsf/8e6fc37a54110e3e852576190052b64d/bf4af7a9fc9bc6f98525
 869600507747?OpenDocument ("Yankee subsequently made a revised statement that the proposed pipeline

there would be sufficient pressure on the Algonquin mainline to support operation of the reference unit at the required pressure of 507 psig.

In addition to the need for sufficient operating pressure on the gas transmission pipeline for the unit to run at capacity, gas must also be available in sufficient quantities to permit the reference unit to run as modeled. To address gas availability, it is important to highlight how the estimated energy and ancillary services (E&AS) revenues for the reference unit are calculated to shed light on the ISO's gas supply assumptions. Concentric developed a simplified economic dispatch model to estimate the net E&AS revenues the reference unit could be reasonably expected to receive in the ISO-NE day-ahead and real-time markets. The dispatch model committed and dispatched the unit economically based on adjusted historical day-ahead and real-time energy and reserve prices, and the unit's production costs operating on natural gas. The unit's production costs included start-up costs, fuel costs, variable operating and maintenance costs, and emission allowance costs. Fuel costs were based on the unit's nominal heat rate multiplied by the natural gas price at the Algonquin City Gate. The natural gas price was also adjusted for a 5% state gross earnings tax which is applicable in Connecticut, and a seasonal intraday gas premium.

The reference unit was not assumed to have a long-term, firm gas transportation and gas supply contract, but rather was assumed to procure gas daily if it is scheduled in the ISO-NE markets.¹² The dispatch model made an economic decision in each hour to determine if the reference unit would run based on the unit-specific parameters and the hourly electricity and gas prices. As noted in the December Report, the dispatch model used historical prices for calendar years 2017-2019. Therefore, the historical prices reflect the supply and demand of natural gas each day, and therefore the availability of gas. If, for example, a day presented cold weather and natural gas prices increased due to increased demand, the unit may not be dispatched if the hourly electricity prices did not cover its increased fuel costs that resulted from those cold weather conditions.

The modeling assumption inherent in the dispatch model is that the observed natural gas price for delivery on the Algonquin main transmission line reflects the availability of gas at that location each day, and at this prevailing market price for gas, there is a willing seller from whom gas can be procured for delivery (on the Algonquin main line). In the absence of long-term contracts for firm gas transportation, this daily market is what gas-fired generators in New England commonly rely upon to arrange natural gas generally. In this respect, the modeling of the reference unit is intended to reflect gas supply practices similar to those (existing) gas-fired generators commonly use.

In this context, it is also important to note that when a new, modern gas-fired generator (in the form of the hypothetical reference unit) operates, it does not necessarily *add to* the gas draw on the gas system in New England. Rather, the new generator will commonly *substitute* for production from another gas-fired generator. In the dispatch model for the reference unit, electricity demand is held constant; therefore, when the reference unit is be dispatched, it would *reduce* the dispatch of another

facilities will have a [maximum allowable operating pressure] of 850 psig.")

¹² This assumption is consistent with our understanding of how gas-fired generators in New England arrange gas to meet their daily schedules and, in particular, that they may not choose to enter into long-term contracts for firm gas transportation from gas-producing regions west of New England (e.g., Marcellus) to New England generation facilities.

competing (existing) generator in the system (and by approximately the same MW). If that other marginal unit is gas-fired and on the same Algonquin pipeline system in particular, the dispatch of the reference unit substitutes for, rather than adds to, the gas drawn from the Algonquin system.

While the CONE and Net CONE analysis does not drill down into specific dispatch scenarios (*i.e.*, which marginal generator would be displaced when the reference unit is dispatched), existing gasfired generation is on the margin in real-time the vast majority (approximately 75%) of all hours in New England.¹³ Thus, it is reasonable to conclude that the reference unit's gas demand would commonly compete (that is, substitute) for the gas demand of another unit, not add to gas demand, during at least some of the hours when the reference unit is dispatched for energy.

In summary, the modeling approach for the reference unit assumes that natural gas can be procured each day at the prevailing gas market price (for delivery on the Algonquin main line); that, in the absence of firm long-term gas transportation contracts, the reference unit would compete for delivered natural gas with other (existing) generators on the system to run as modeled; and, based on the observations above concerning gas pressures, there would be sufficient pressure on the Algonquin mainline to support the operation of the reference unit at capacity. For these reasons, it is reasonable to conclude the reference unit would be able to acquire and to access sufficient natural gas to run as modeled.

Addendum Exhibits:

Exhibit A: Gas and Electric Interconnection Map Exhibit B: Potential Reference Unit Site Locations Map Exhibit C: Correspondence with GE Regarding Emissions Exhibit D: Correspondence with GE Regarding Gas Pressure Requirements

¹³ *See* ISO-NE 2019 Annual Markets Report, p. 101, available at <u>https://www.iso-ne.com/static-assets/documents/2020/05/2019-annual-markets-report.pdf</u>
Exhibit A: Gas and Electric Interconnection Map



N ∕∕

County Boundaries

------ 345kV Transmission Line

Columbia Laki

- ---- 345kV Transmission Line, 2-mile border
- Gas Transmission Main Pipelines
- ---- Gas Transmission Main Pipelines, 2-mile border
 - Gas Transmission Lateral Pipelines

The Yellow cloud represents green-space locations that could be used as a potential location for a proposed facility

1 mile

Windham County

NORTH

MANSFIELD

CONANTVILL

New London County

289

PERKINS CORNER



Exhibit B: Potential Reference Unit Site Locations Map



- 345kV Transmission Line
- 345kV Transmission Line, 2-mile border
- Gas Transmission Main Pipelines
- Gas Transmission Main Pipelines, 2-mile border
- Gas Transmission Lateral Pipelines
 - Approximate Floodplain Boundary
 - The Yellow square represents 8-acre greenspace locations that could be used as a potential location for a proposed facility

PERKINS CORNER

Mansfield Athletic crimple

> Eastern Connecticut State University

Exhibit C: Correspondence with GE Regarding Emissions

Keith Paul

From: Sent: To: Subject: Stroganow, Peter P (GE Gas Power) < peter.stroganow@ge.com> Tuesday, March 9, 2021 3:02 PM Keith Paul RE: Emissions Question

Keith,

We are not aware having an emissions issue on NG at the site we have operating in the configuration described below. 7HA.02 exhaust gas NOX emissions are 25 PPM or below. A 90% effective SCR would have no issue achieving 2.5 PPM NOX at the stack.

Warmest Regards, **Peter Stroganow** Senior Sales Manager – New England and Eastern Canada GE, Gas Power Systems

M +1 518 698 3408 peter.stroganow@ge.com

GE imagination at work

For a current view and tracker of the HA fleet you can visit gepower.com/ha

P.S. To access a soft copy of our 2019 Product Catalog, please click here: https://www.gepower.com/gas/catalogs

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From: Keith Paul <Keith.Paul@mottmac.com> Sent: Tuesday, March 2, 2021 2:00 PM To: Stroganow, Peter P (GE Gas Power) <peter.stroganow@ge.com> Subject: EXT: Emissions Question

Pete,

We are getting feedback that it is difficult for a Simple Cycle dual fuel 7HA.02 with High Temperature SCR and CO catalyst with Air Dilution Fans to make 2.5 ppm NOx on Natural Gas fuel. I am surprised by that feedback. Is 2.5 ppm NOx a concern?

What NOx levels would be coming out of the GT to achieve 2.5 ppm NOx at the stack, and are such values reasonable to attain/achieve?

Thank you, Keith

Keith Paul Senior Consulting Engineer D 781-636-4070



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Exhibit D: Correspondence with GE Regarding Gas Pressure Requirements

Keith Paul

From: Sent: To: Subject: Stroganow, Peter P (GE Gas Power) < peter.stroganow@ge.com> Friday, March 12, 2021 4:05 PM Keith Paul Re: EXT: 7HA.02 Gas Pressure needs

Keith,

Estimate the fuel pressure requirement to be ~ 507psig (simple linear interpolation from 0 ft 59F and 0ft -20F.)

Project specific pressure requirements would require design engineering engagement based on specific fuel composition analysis and site conditions among others.

Warmest Regards,

Pete

Sent from my iPhone

On Mar 10, 2021, at 11:06 AM, Keith Paul <keith.paul@mottmac.com> wrote:

Pete,

ISO-NE would like to also submit this to FERC to show our gas pressure is adequate all year long. So can I share your response to this request as well?

Can we use the following site criteria to determine the minimum gas pressure required for a new 7HA.02? Winter Ambient Temp 13F Elevation 250 FASL

Thank you very much, Keith

Keith Paul Senior Consulting Engineer

D 781-636-4070 keith.paul@mottmac.com

From: Stroganow, Peter P (GE Gas Power) <peter.stroganow@ge.com> Sent: Wednesday, March 10, 2021 9:20 AM To: Keith Paul <Keith.Paul@mottmac.com> Subject: Fwd: EXT: 7HA.02 Gas Pressure needs

Sent from my iPhone

Begin forwarded message:

From: "Kos, Andrew S (GE Gas Power)" <<u>andrew.kos@ge.com</u>> Date: March 10, 2021 at 8:32:55 AM EST To: "Stroganow, Peter P (GE Gas Power)" <<u>peter.stroganow@ge.com</u>> Subject: RE: EXT: 7HA.02 Gas Pressure needs

Here you are Pete. Reference for 7HA.02 gas pressure requirements.

Thanks, Andy

<image002.png>

From: Stroganow, Peter P (GE Gas Power) <<u>peter.stroganow@ge.com</u>> Sent: Tuesday, March 9, 2021 5:03 PM To: Kos, Andrew S (GE Gas Power) <<u>andrew.kos@ge.com</u>> Subject: Fwd: EXT: 7HA.02 Gas Pressure needs

Yo buddy

Sent from my iPhone

Begin forwarded message:

From: Keith Paul <<u>keith.paul@mottmac.com</u>> Date: March 9, 2021 at 5:02:38 PM EST To: "Stroganow, Peter P (GE Gas Power)" <<u>peter.stroganow@ge.com</u>> Subject: EXT: 7HA.02 Gas Pressure needs

Peter,

What gas pressure range is required for a 7HA.02 in simple cycle? Has the pressure requirement changed since the 7HA.02 was first introduced as you started to offer the low minimum load at 25% load as opposed to the older 40% or 50% minimum load numbers?

Thank you, Keith

Keith Paul

Senior Consulting Engineer D 781-636-4070 keith.paul@mottmac.com

<image004.png></image004.png>	Mott MacDonald
	101 Station Drive
	Suite 130
	Westwood
	MA 02090
	United States of America
Website Twitter LinkedIn Facebo	<u>ook</u> <u>Instagram</u> <u>YouTube</u>

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¥	×	•				FG1 p	pressure PSIG (barg)				Upstrea	m equipment	pressure drop 🔄
				59F /15C			-20F /-28.9C	-		120F /48.9C				
New Unit Heavy Duty Gas Turbine	Design Pressure PSIG	Maximum Operating	0 (zero) feet	3000 feet	6000 feet	0 (zero) feet	3000 feet	6000 feet	0 (zero) feet	3000 feet	6000 feet		Coriolis flow	Gas conditionning
Frame Size	(Barg)	Pressure PSIG (barg)	Elevation	Elevation	Elevation	Elevation	Elevation	Elevation	Elevation	Elevation	Elevation	SSOV	meter	skid
7HA.02	670 (46.2)	605 (41.7)	475 (32.8)	425 (29.3)	385 (26.5)	530 (36.5)	480 (33.0)	430 (29.6)	430 (29.6)	390 (26.9)	350 (24.1)	5 (0.35)	5 (0.35)	15 (1)

Attachment I-1d

April 2021 ORTP Report Addendum

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

ADDENDUM – ORTP

APRIL 2021

CONCENTRIC ENERGY ADVISORS, INC.

MOTT MACDONALD





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SECTION 1: SUMMARY

A. Overview

ISO-NE engaged Concentric Energy Advisors, Inc. (Concentric) to conduct an independent analysis of the Cost of New Entry (CONE)/Net CONE and Offer Review Trigger Price (ORTP) values for the sixteenth Forward Capacity Auction (FCA 16). Concentric and its subcontractor, Mott MacDonald, worked together to develop the recommendations presented in a report finalized in December 2020 (December Report).

This addendum is provided as a supplement to the original December Report that explains revisions to the ORTPs as a result of updated tax laws relating to renewable resource tax credits.

On December 27, 2020, the Consolidated Appropriations Act, 2021 was signed into law, providing an extension of the beginning of construction deadline for the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) for certain types of facilities. These changes have impacted the ORTP calculations presented in the December Report, and have resulted in a revised solar photovoltaic (PV) resource ORTP value below the assumed Forward Capacity Auction (FCA) Starting Price.¹ The original December Report did not include an ORTP for a solar resource as the estimated value was above the estimated FCA Starting Price based on information known at the time the value was calculated.

The ISO filed CONE/Net CONE, and Capacity Performance Payment Rate (PPR) values in December 2020,² and submitted updated CONE, Net CONE and PPR values on March 30, 2021 in response to a Commission deficiency notice.³ The revised PPR will change from \$8,782 to \$8,894/MWh. All ORTP values have been updated to reflect this revised PPR. The effect of the PPR update is an approximately \$0.01/kW-mo. reduction in the ORTPs.

Additional details regarding these calculations are described below.

B. Summary of Recommendations

Based on the update to the tax law changes and the revised PPR value, we recommend the following ORTP values shown in Table 1.

¹ An ORTP value was calculated for solar resources participating as demand capacity resources, specifically, on-peak demand capacity resources. The change in the ITC did not impact the ORTP value calculated for this resource type as the ITC benefit was assumed to be included in the capital cost of the resource.

² See ISO New England Inc., Updates to CONE, Net CONE, and Capacity Performance Payment Rate, Docket ER21-787-000 (filed December 30, 2020).

³ See ISO New England Inc., Response to Commission Deficiency Notice and Revised CONE, Net CONE, and Capacity Performance Payment Rate Values, Docket ER21-787-000 (filed March 30, 2021).

		GENERATING	DEMAND CAPACITY RESOURCES					
R eference Technology	Combined Cycle	COMBUSTION TURBINE	Onshore Wind	Battery ⁵	Solar	Energy Efficiency	DR - On- Peak Solar	LOAD MGMT C&I/PREV INSTALLED DG ⁵
Nominal Installed Capacity (MW)	557	376	82.5	150	20			
QUALIFIED CAPACITY (MW)	501	361	32.4	150	3.8		1	0.5
Installed Cost (2019\$/kW)	956	758	2,097	938	1,524			
REAL ATWACC	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%
Gross CONE (2025\$/кW-мо)	\$12.72	\$9.18	\$18.64	\$8.92	\$9.64	\$36.95	\$20.07	\$15.41
REVENUE OFFSETS (2025\$/kW-mo)	\$3.89	\$4.04	\$23.28	\$6.01	\$9.37	\$45.52	\$14.66	\$14.66
NET CONE (2025\$/kW-mo) INSTALLED	\$8.83	\$5.14	-\$4.63	\$2.91	\$0.26	-\$8.57	\$5.41	\$0.75
ORTP (2025\$/kW-mo) QUALIFIED	\$9.811	\$5.355	\$0.00	\$2.912	\$1.381	\$0.00	\$5.414	\$0.750

Table 1: ORTP Summary for Specific Resources (2025\$)⁴

⁴

The values shown assume the continuation of the Forward Reserves Market (FRM). Qualified capacity values are corrected from pp. 11, 98 in the December Report. 5

SECTION 2: ORTP STUDY – SOLAR PV RESOURCE

A. Approach

The objective of the ORTP study is to develop ORTP values for FCA 16 for the 2025/2026 Capacity Commitment Period. The recommended ORTP values presented below were set at the low end of the competitive range of expected values, which would only subject resource offers that appear commercially implausible to Internal Market Monitor (IMM) review. In addition, consistent with the ISO Transmission, Markets, and Services Tariff (Tariff) requirements, all resources were assumed to have a contract for their output.⁶

B. Financial Assumptions

Consistent with the approach used to calculate ORTPs for other technologies, the calculation of an ORTP value for the solar PV resource required a real discount rate to translate uncertain future cash-flows to a levelized revenue requirement. The financial assumptions used in the ORTP analysis, which are consistent with the financial assumptions used for all of the resources for which an ORTP value was calculated, are shown in Table 2 below.⁷

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

Table 2: ORTP Financial Assumptions

C. PTC/ITC for Qualifying Resources

Legislation enacted in December of 2020 provides an allowance for tax credits for eligible renewable energy resources in the form of a Production Tax Credit (PTC) or an Investment Tax Credit (ITC). The PTC is not available to facilities that begin construction after December 31, 2021. Accordingly, the

⁶ *See* Market Rule 1, Appendix A, Section III.A.21.1.2.

⁷ The 2014 Brattle and the 2017 Concentric ORTP studies also assumed consistent financial assumptions across each respective study's ORTP analyses. *See* Demand Curve Changes, FERC Docket No. ER14-1639-000 (filed April 1, 2014); and ISO New England Inc. Filing of CONE and ORTP Updates, FERC Docket No. ER17-795-000 (filed January 13, 2017).

PTC is not considered in this ORTP analysis. However, the ORTP study does include a 26% ITC for a solar PV resource that begins construction by December 31, 2022, as shown below.⁸

YEAR CONSTRUCTION BEGINS	ITC
2019	30%
2020	26%
2021	26%
2022	26%
2023	22%
After 2023	10%

Table 3 : ITC Assumptions

D. 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 approach is supported by Federal Energy Regulatory Commission precedent, finding that "default MOPR values should maintain the same basic financial assumptions, such as the 20 -year asset life, across resource types"⁹ in keeping with the 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."¹⁰

E. ORTP Solar Technical Specifications

Based on consultation with Mott MacDonald, the solar PV facility was assumed to be a 20 MW facility located in Connecticut. The assumed size of the solar facility was based on recent and expected entry by similar resource types in the FCA. Connecticut was selected as an appropriate location for the solar facility because there are currently similar facilities of this type located nearby. The solar PV facility was assumed to consist of 69,984 400-Watt modules mounted on fixed racks at a tilt of 30 degrees. Power was assumed be transmitted to a central switchyard, converted to alternating current, transformed up to 115 kV, and injected into the site-adjacent 115 kV network.

⁸ For solar technology, this required an extension of the construction schedule from 16 months to 30 months.

⁹ See Calpine Corporation v. PJM Interconnection, L.L.C., 171 FERC ¶ 61,035 (2020) at P 290, citing Calpine Corporation v. PJM Interconnection, L.L.C., 169 FERC ¶ 61,239 (2019) at P 153.

¹⁰ *Calpine Corporation v. PJM Interconnection, L.L.C.,* 169 FERC ¶ 61,239 (2019) at P 153citing *PJM Interconnection, L.L.C.,* 143 FERC ¶ 61,090 (2013) at P 144.

The solar PV scope of work included fixed position solar PV arrays, as opposed to single-axis solar tracking designs. This fixed position design was selected because solar tracking has been found to be difficult to justify on a cost basis due to the historically low irradiance that occurs in the New England region. Fixed position solar arrays are also consistent with a majority of the solar projects already developed in the New England region, as well as newer solar projects participating in recent FCAs.

F. Solar Capital/Operating Costs

The table below summarizes operating costs for the solar PV resource, described in further detail in the following sections.

	SOLAR PV
\$/kW-year	
Property Taxes	1.36
Site Leasing	9.98
Insurance	4.59
Fixed O&M (LTSA plus ongoing O&M)	14.86
Total Fixed Expenses	30.79
(\$/kW-month)	
Property Taxes	0.11
Site Leasing	0.83
Insurance	0.38
Fixed O&M (LTSA plus ongoing O&M)	1.24
Total Fixed Expenses	2.57

Table 4: Summary of ORTP Operating Costs (2025\$ Levelized)

To estimate capital costs for the reference solar PV unit, Concentric reviewed recently developed and current planned projects in New England to assess the appropriate size and location. We then consulted with Mott MacDonald to estimate capital costs for the reference solar PV unit. The largest components of the solar PV unit's capital costs include major equipment, racking system, foundations, SCADA and monitoring systems, electrical plant, interconnection, testing/energization, and other indirect costs as well as owner's costs. These estimates were based on Mott MacDonald's proprietary database of project costs. This database is continuously developed using active Mott MacDonald Solar PV projects. A summary of the assumed overnight capital costs for the solar PV unit are included in Table 5 below.

	Solar
EPC Costs	
Civil/Structural/Architectural	1.3
Electrical/Instrumentation Costs	1.6
Construction Management	0.8
Major Equipment - PV Modules, PV Inverters, PV Racks, Batteries	15.1
Solar SCADA & Monitoring	0.2
Testing & Energization	0.1
Other Indirect Costs	2.5
Project Contingency	1.1
Owners Development Costs	<u>0.7</u>
Total EPC	23.5
Non-EPC Costs	
Owner's Contingency	0.07
Electrical Interconnection	5.7
Electrical System Upgrade Costs/Substation Upgrades	0.0
Financing Fees (4% of costs financed through debt)	0.9
Working Capital (1% of EPC costs)	0.2
Total Non-EPC	7.0
Total Overnight Capital Costs	30.5
\$/kW	1,524

Table 5: Reference Solar PV Overnight Costs (2019\$, in millions)

Concentric estimated fixed operating and maintenance (O&M) costs for the solar PV resource through consultation with Mott MacDonald and a review of solar leasing agreements. Land lease costs are typically negotiated and are therefore challenging to calculate. Concentric reviewed data from several publicly available solar PV land lease agreements to estimate a reasonable range of land lease costs on a \$/acre basis. The range of these costs was approximately \$7,500/MW-year to \$38,000/MW-year. For purposes of the ORTP study, Concentric focused on the low end of the range of observable land lease costs. The average of this selection was approximately \$10,000/MW-year, which was also relatively close to the land lease costs for the projects reviewed in Connecticut (the location of the reference resource used in the ORTP study). This resulted in a land leasing cost assumption of approximately \$1,500/acre or \$9.98/kW-year (2025\$).

It was determined that a property tax rate of 1% was representative of projects that have entered into Payment In Lieu of Taxes (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 Windham County, Connecticut to ensure the reasonableness of the ORTP property tax assumption. Property taxes for towns in Windham County from 2018-2020 range from 2.0% to 4.3%, with an average of 2.91%. 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 solar farm were estimated at approximately \$27,000 per year, or \$1.36/kW-year (2025\$).

Insurance costs were assumed to be 0.3% of installed costs, consistent with the other technologies evaluated in this study. Annual insurance costs were estimated to be approximately \$90,000 in 2025 dollars, or \$4.59/kW-year.

Long Term Service Agreement (LTSA) and ongoing maintenance costs were assumed to be \$14.86/kW-year in 2025\$ based on consultation with Mott MacDonald. Concentric also reviewed several publicly available studies which include estimates of solar PV fixed O&M costs. The results of this review confirmed the assumed cost as a conservative, low-end of the range assumption.

Each of the above assumptions are estimations of costs, since publicly available information on each of these cost categories is very limited and extremely site-specific. Based on these assumptions, we calculated a levelized fixed O&M cost for the reference solar PV resource of \$2.57/kw-month in 2025 dollars.

G. Revenue Offsets for Solar PV ORTP Resource

This section summarizes the estimated revenue offsets used for the solar PV resource. ORTP revenue offsets come from one or more of the following potential revenue streams: energy and ancillary services (E&AS) revenues, Pay for Performance (PFP) revenues, or Renewable Energy Credit (REC) revenues. The E&AS estimates for the solar ORTP resource were developed with simplified dispatch models that used historical energy prices from 2017-2019 that were modified with an Energy/Reserve Scarcity adjustment. The prices used in the solar PV ORTP dispatch model do not include an LOE adjustment, but rather reflect expected prevailing excess supply conditions.

i. Scarcity

Estimated energy revenues from high-price "scarcity" periods during real-time reserve shortages were added as a separate line to the financial model, outside of the ORTP dispatch model. The Energy/Reserve Scarcity Adderfor the solar unitassumed 7.4 scarcity hours annually, which is based on the ISO's modeling given expected prevailing excess supply conditions. The Energy/Reserve Scarcity Adder is shown in Table 6.

Unit	AVAILABILITY FACTOR	Adjustment \$/kW-mo
Solar	47.81%	0.29

Table 6: ORTP Energy/Reserve Scarcity Adjustment

ii. Pay for Performance

PFP revenues were included in the revenue offsets for the solar PV resource, based upon expected scarcity hours, performance during scarcity hours, and the system's balancing ratio during scarcity conditions. The calculation assumed 7.4 scarcity hours and a balancing ratio of 81.6%. The values for the solar PV resource is shown in the table below.

TECHNOLOGY	Performance Payment Rate (\$/MWH)	Average Actual Performance [A]	Average Balancing Ratio	Net Performance Payments (\$/kW-m0)
Solar	8,894	47.8%	0.816	0.48

Table 7: Resource-Specific Values

iii. E&AS

The solar PV facility was modeled as located in Connecticut. Historical generation data from existing solar facilities in New England was used to estimate an hourly generation profile for the solar unit. The hourly generation profile is based on a daily average hourly capacity factor (i.e., one 24-hour generation profile for each month) of solar facilities in Massachusetts and Connecticut in each month during the 2017-2019 period for all facilities with a commercial online date of January 2016 or later. The solar PV facility's E&AS revenues were calculated using the same dispatch logic as the onshore wind unit in the December 2020 Report. The solar PV unit offered 53% of its generation into the day-ahead market and 100% of its output into the real-time market, with variable 0&M costs assumed to be zero. Given the unit's location, the solar dispatch model used prices from Connecticut zone adjusted with the Energy/Reserve Scarcity Adder.

iv. Renewable Energy Credits

Revenue offsets for solar PV resource includes renewable energy credits (RECs). The REC revenues for these resources are 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.¹¹ 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 to 2025 dollars.¹² The annual REC prices were used to calculate annual REC revenues for the solar PV resource. The REC price was also used in the dispatch models to establish the hourly offer prices of each unit. The resulting REC price is \$29.32/MWh.

¹¹ REC price data sourced from SNL Financial.

¹² Though RECs are traded beyond their vintage year, our average does not include those prices as they would have skewed the estimate downward.

Attachment I-1e

Danielle Powers Testimony

DIRECT TESTIMONY

OF

DANIELLE S. POWERS CONCENTRIC ENERGY ADVISORS, INC.

ON BEHALF OF

ISO NEW ENGLAND

SPONSORING ATTACHMENT DSP-1

DIRECT TESTIMONY OF DANIELLE S. POWERS ON BEHALF OF ISO NEW ENGLAND

1		1. <u>INTRODUCTION</u>
2	Q1.	Please state your name and business address.
3	A1.	My name is Danielle S. Powers. My business address is 293 Boston Post Road West, Suite
4		500, Marlborough, Massachusetts 01752.
5	Q2.	By whom are you employed and in what position?
6	A2.	I am a Senior Vice President with Concentric Energy Advisors, Inc. ("Concentric").
7	Q3.	Please describe Concentric.
8	A3.	Concentric is a management consulting and economic advisory firm focused on the North
9		American energy and water industries. Concentric specializes in regulatory and litigation
10		support, transaction-related financial advisory services, energy market strategies, market
11		assessments, energy commodity contracting and procurement, economic feasibility
12		studies, and capital market analyses and negotiations.
13	Q4.	What are your responsibilities in your current position?
14	A4.	As a consultant, my responsibilities include assisting clients in identifying and addressing
15		business issues. My primary areas of focus are wholesale energy market design and
16		operation, resource planning, and power generation.
17	Q5.	Please summarize your educational background.

A5. I have a Bachelor of Science in Mechanical Engineering from the University of
 Massachusetts Amherst and a Master of Business Administration from Bentley University.

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Q6. Please summarize your professional qualifications.

A6. I have approximately thirty years of direct experience in the public utility industry. I have worked for an investor-owned utility, an independent system operator, and most recently as a consultant. I have managed and/or participated in a wide variety of consulting engagements. A copy of my CV and testimony listing is attached as Attachment DSP-1.

6 Q7. Have you previously testified in any regulatory proceeding?

7 A7. Yes. I have provided expert testimony or reports before the Federal Energy Regulatory
8 Commission ("FERC" or "Commission"), the Illinois Commerce Commission, the Indiana
9 Utility Regulatory Commission, the Connecticut Siting Council, and the Massachusetts
10 District Court. My previous testimony has typically addressed issues related to wholesale
11 energy market design and resource planning.

12 Q8. On whose behalf are you testifying in this proceeding?

- 13 A8. I am testifying on behalf of ISO New England Inc. (the "ISO" or "ISO-NE").
- 14

2. PURPOSE AND SUMMARY OF TESTIMONY

15 Q9. What is the purpose of your direct testimony in this proceeding?

A9. My direct testimony is focused on providing an overview of our approach to developing
an Offer Review Trigger Price ("ORTP") for an offshore wind facility, consistent with
Market Rule 1, Section III.A.21.1.2 of the ISO Transmission, Markets and Services Tariff
("ISO Tariff"). Concentric was engaged by the ISO to conduct an independent analysis of
the ORTP values for the sixteenth Forward Capacity Auction ("FCA 16").

21 Q10. What was involved in the calculation of ORTPs?

22 A10. The analysis involved screening several technologies and performing a "bottom-up"

1 engineering-economic analysis of those technologies that met the ORTP screening criteria. 2 For each resource technology we studied, this "bottom-up" analysis included a detailed analysis of resource technical specifications, capital expenses, operating costs, and 3 4 expected competitive market revenues in order to calculate the expected remaining revenue 5 that a resource would require from the capacity market to be financially viable. To perform 6 this calculation in accordance with the requirements of the ISO Tariff, we used a capital 7 budgeting model (also referred to here as the discounted cash flow analysis) that 8 incorporated the capital expenses, operating costs, expected energy and ancillary services 9 revenues from the ISO-administered markets, and assumptions regarding debt and equity 10 rates, capital structure, depreciation, taxes and discount rate. The ORTP benchmarks are equal to the net present value of the levelized costs of each resource, net of certain expected 11 12 market revenues, or (using the terminology of the ISO Tariff), "[t]he Offer Review Trigger Price is set equal to the year-one capacity price output from the model." Further, to comply 13 14 with Commission precedent, we use financial assumptions that are intended to ensure the 15 resulting ORTP benchmarks reflect the low end of the competitive range of possible offers 16 from a resource of the specified technology. This objective strikes a reasonable balance by not subjecting offers that are "clearly competitive" to unnecessary review by the ISO's 17 18 Internal Market Monitor.

19 011.

20

Did vou utilize this same approach for calculating the ORTP values for all technology types, including offshore wind?

21 A11. Yes, we did. The method and detail for calculating ORTPs for each technology type is 22 explained in significant detail in the Net CONE/ORTP Report prepared by Concentric and Mott MacDonald (the "CEA Report"), which the ISO is including with its filing of the 23

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ORTP values.¹ We utilized the same method summarized above and detailed in the CEA Report for establishing an ORTP value for the offshore wind reference unit.

3 Q12. Is your evaluation of the offshore wind ORTP included in the CEA Report?

4 A12. No, it is not. Per the ISO Tariff, ORTPs are to be established only where the resulting 5 value would be below the starting price of the Forward Capacity Auction ("FCA"). As summarized on p. 10 of the CEA Report, the ORTP for offshore wind would be above the 6 7 starting price for FCA 16. As a result, we did not include a detailed accounting of the 8 analysis we performed for offshore wind in the CEA Report. Therefore, I will provide that 9 explanation in this testimony. In support of our analysis, Mott MacDonald performed the capital cost analysis for the reference offshore wind facility. Their analysis is explained in 10 11 detail in the Mott MacDonald Report that is also included with the ISO's filing. I refer to 12 this report throughout my testimony.

13 Q13. Please provide a high-level overview of the analysis you performed for the offshore

14 wind technology.

A13. The "bottom-up" analysis involved four basic steps: i) determining an appropriate,
 representative size for the "reference" offshore wind project in New England; ii) selecting

¹ The CEA Report was originally filed in support of the ISO's submittal of the Cost of New Entry ("CONE"), Net CONE and Capacity Performance Payment Rate ("PPR") values on December 31, 2020. See ISO New England Inc., Updates to CONE, Net CONE, and Capacity Performance Payment Rate, Docket No. ER21-787-000 (filed December 31, 2020) ("FCA 16 CONE Filing"). In response to a deficiency notice issued by the Commission on the FCA 16 CONE FFERC Filing, the ISO submitted revised FCA 16 CONE Values in that proceeding on March 30, 2021. ISO New England Inc., Response to Commission Deficiency Notice and Revised CONE, Net CONE, and Capacity Performance Payment Rate Value, Docket No. ER21-787-000 (filed March 30, 2021). That filing included an addendum to the CEA Report (the "CONE Addendum"). Because the PPR is an input into the ORTP calculations, the CONE Addendum is also being filed in this proceeding with the ORTP values. Finally, to address the extension of the Investment TaxCredit applicable to certain renewable technologies, which the U.S. Congress passed into law in late December 2020, we further updated the ORTP values, as addressed in the ORTP Addendum to the CEA Report that is also being filed in this proceeding. The original report, the CONE Addendum, and the ORTP Addendum, are collectively referred to herein as the CEA Report.

1 a representative location; iii) developing a capital cost estimate by determining an 2 engineering-based project scope of work, including design, engineering, construction, and 3 development, with associated capital cost allowances; and iv) conducting a discounted cash 4 flow ("DCF") analysis over a twenty year period based on reasonable financial 5 assumptions and reasonable energy revenue assumptions to calculate an ORTP value.

In the remainder of this Section 2, I explain the application of steps i) and ii), as well as 6 7 several important assumptions used in the analysis. In Section 3, I address the financial 8 horizon modeling assumptions employed for the analysis. While the use of a 20-year 9 financial horizon for the ORTP calculation is an express requirement of the ISO Tariff, it 10 was a point of contention during discussions with stakeholders. It is therefore important to 11 explain why the use of the 20-year financial horizon is appropriate. In Section 4, I explain the application of the Investment Tax Credit ("ITC") to the reference offshore wind project. 12 13 In Section 5, I walk through the details of the DCF analysis that we performed for the offshore wind technology, including the role of the capital cost estimation in this 14 15 calculation, which is addressed in greater detail in the Mott MacDonald Report. Finally, 16 in Section 6, I review the capital cost benchmarking that Concentric performed, which 17 demonstrates that Mott MacDonald's capital cost estimate for a large-scale offshore wind 18 project in New England is at the low end of comparable estimates that are contained in 19 other studies of offshore wind capital costs.

20

21

Q14. Please describe the first two steps, addressing the size and location of the reference offshore wind project.

A14. In determining an appropriate size for the offshore wind facility, we modeled the
 hypothetical offshore wind project with a nominal installed capacity of 800 megawatts

("MW"). This size was selected because it is consistent with the size of several planned
 offshore wind projects off the coast of southeastern New England.²

3 In terms of location, we assumed that the reference offshore wind facility would be located off the southeastern New England coast and interconnect at the Brayton Point site in 4 5 Somerset, MA. This is based on the fact that there are a set of adjacent offshore wind lease 6 areas for offshore wind development approximately sixty miles off the southeastern New 7 England coast, where new offshore wind development serving New England is expected. 8 From those offshore wind lease areas, marine cables would connect the reference project 9 to sufficient land-based transmission infrastructure to accommodate the reference project's 10 capacity. By using existing infrastructure at the Brayton Point site, we are able to minimize 11 any required electric system upgrades, as more fully explained in the Mott MacDonald Report.³ Figure 1 below shows the general offshore wind lease areas where offshore wind 12 13 development is presently expected off the southeastern New England coast, and a variety of hypothetical interconnection points to the existing New England transmission system 14 15 for offshore wind projects that have been identified in prior ISO planning studies.⁴

² These projects include Revolution Wind (704 MW), Vineyard Wind (800 MW), and Mayflower Wind (804 MW). See National Renewable Energy Laboratory "Comparing Offshore Wind Energy Procurement and Project Revenue Sources Across U.S. States", Table A-2, p. 41, available at <u>fhttps://www.nrel.gov/docs/fy20osti/76079.pdf</u>.

³ Mott MacDonald Report, Section 4.3.

⁴ 2019 Economic Study: Significant Offshore Wind Integration, ISO New England, June 30, 2020, p. 7, *available at* <u>https://www.iso-ne.com/static-assets/documents/2020/10/2019-anbaric-economic-study-final.docx</u>.



Figure 1: Location of Announced Offshore Wind Projects and Lease Areas

2

Q15. Please summarize the approach to your analysis regarding the third step in the ORTP calculation process for the offshore wind technology - the determination of estimated capital costs for the reference offshore wind project.

A15. Estimated capital costs, including the upfront capital expense, represent a major component of the total installed cost for the offshore wind facility, and therefore a major determinant of its ORTP. As I explained above, in order to estimate these costs, we retained the engineering firm Mott MacDonald, which has significant experience with the development of offshore wind facilities throughout the world. Mott MacDonald utilized available information in their proprietary database, their knowledge and assessment of a proper engineering scope of work for the reference offshore wind facility in the identified location,

1 as well as publicly available information on offshore wind projects currently in 2 development. The offshore wind capital cost estimate was largely based on cost 3 component data and development experience from large-scale offshore wind projects in 4 the North Sea in which Mott MacDonald has been directly involved. However, because 5 offshore wind development costs can differ dramatically from region to region, 6 adjustments for cost differences appropriate to New England were necessary. This analysis 7 is explained in detail in the Mott MacDonald report⁵, which I discuss below as well. It is 8 also important to note that there is no completed large-scale offshore wind project (i.e., 9 equivalent to the 800 MW reference project size studied) operating in the U.S.

10 Therefore, in order to minimize the uncertainty of the overnight capital cost estimates for 11 this resource type, and to fully account for regional cost differences, we relied on Mott 12 MacDonald's extensive expertise in identifying and analyzing the key variables that would 13 be expected to drive the cost of developing an offshore wind facility in the New England 14 region. These costs are more fully explained in the accompanying Mott MacDonald 15 Report. The Mott MacDonald Report should be read and considered in parallel with the 16 ORTP model and assumptions discussed in this testimony.

17 Q16. Please summarize other key assumptions that were used in your analysis.

A16. Our analysis included eligibility for the latest ITC established by Congress in late
 December of 2020 under the Consolidated Appropriations Act, 2021 (the "2021
 Appropriations Act"), which was signed into law on December 27, 2020. The 2021
 Appropriations Act provided an extension of the beginning of construction deadline for the

[.]

Mott MacDonald Report, Section 4.

Production Tax Credit ("PTC") for wind projects and new ITC provisions for solar and
 offshore wind, among other things.

Beyond the ITC, we made other key financial assumptions regarding the project's initial debt term, its after-tax weighted average cost of capital ("ATWACC"), Renewable Energy Credit ("REC") market prices, and energy market net revenues in the ISO-administered markets. The debt term and ATWACC assumptions applied broadly to all resources included in the ORTP analysis and are covered thoroughly in the CEA Report accompanying this filing. Other offshore wind-specific assumptions and analysis are discussed more fully below.

10

3. FINANCIAL HORIZON MODELING ASSUMPTIONS

11 Q17. What financial horizon is used for performing the DCF analysis for offshore wind?

12 A17. Pursuant to the ISO Tariff, "the model looks at 20 years of real-dollar cash flows discounted 13 at a rate (Weighted Average Cost of Capital) consistent with that expected of a project 14 whose output is under contract (i.e., a contract negotiated at arm's length between two 15 unrelated parties)."⁶

16 Q18. Is this financial horizon appropriate for offshore wind?

17 A18. Yes, it is. There are three main factors that are considered in determining the financial 18 horizon over which the costs and revenues of a generating facility—including an offshore 19 wind facility—are modeled and the ORTP value is calculated. These include: i) the 20 assumed debt amortization horizon; ii) the facility's expected physical life; and (iii) the 21 project's expected operating life. Each of these must be accounted for in establishing the

⁶ Market Rule 1, Appendix A Subsection 21.1.2(b).

financial horizon that is appropriate for performing the DCF analysis. Per the ISO Tariff, we used 20 years for all three of these modeling horizon parameters.⁷ As I will explain further below, this is fully consistent with the duration of publicly-available long-term Power Purchase Agreements ("PPAs") that have been executed in New England for the development of larger (400 to 800 MW) new offshore wind projects in the region.

6 **O19**.

Q19. Are these concepts interchangeable?

A 19. No, they are not. These are distinct and different modeling concepts and assumptions that
are frequently conflated but represent components of a horizon over which to analyze an
investment. The proper determination of this investment horizon has a material impact on
a project's overall costs and its ORTP value.

- 11 Q20. Conceptually, what is a debt amortization horizon?
- A20. The debt amortization horizon, or "debt term" for short, represents the number of years
 over which the debt incurred to develop the project is to be fully repaid to lenders.

14 Q21. How did you determine the debt term assumption used in calculating the offshore 15 wind ORTP value?

- 16 A21. The ORTP study assumed a 20-year debt term based on the assumption that the modeled 17 offshore wind facility is operating under a PPA, consistent with ISO Tariff requirements.
- 18
 - This is consistent with recently announced offshore wind projects, which have disclosed

⁷ Id.

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that they are being developed under 20 year PPAs.⁸

3 4

O22. Is this consistent with your understanding of how generating facilities are financed?

A22 Yes. It is reasonable to assume that a lender would consider the time horizon of the PPA in providing financing for a generating facility and would rely on the timely repayment of 5 the debt over the term of the PPA.

6 Q23. Is it reasonable to assume a debt term longer than the PPA term?

7 A23. No. There is no assurance of revenue needed to repay debt beyond the PPA term. This is 8 a particularly important consideration with facility types that have not yet been built and 9 for which there is limited operating experience in the United States. Beyond the PPA term, 10 there is significant uncertainty around offshore wind revenues and operating costs. 11 Therefore, it is not reasonable to conclude that lenders would originate debt prior to a 12 project's initial development for a horizon greater than the initial contracted revenue period 13 provided under the PPA of 20 years. Based on my experience, an assumption that includes 14 debt payment consistent with the PPA life for an offshore wind facility is reasonable.

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See also Vineyard PPA: D.P.U. 18-76/18-77/18-78, Exhibits JU-3-A and JU-3-B, Offshore Wind Generation Unit Power Purchase Agreement Between NSTAR Electric Company d/b/a Eversource Energy and Vineyard Wind LLC, dated as of July 31, 2018, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9676522 and https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9676523. See also Bay State Press Release: https://media.orrick.com/Media%20Library/public/files/insights/orrick-offshore-wind-energy-updateand-outlook-ianuary-2020.pdf.

See National Renewable Energy Laboratory "Comparing Offshore Wind Energy Procurement and Project Revenue Sources Across U.S. States", Table A-2, p. 41, available at https://www.nrel.gov/docs/fy20osti/76079.pdf.
Q24. Is the assumed debt term a material assumption in the calculation of the offshore wind ORTP value?

A24. Yes. The assumed debt life is a determining factor in the calculation of the ORTP value. If one assumes a debt life in excess of the PPA term, the true cost of the facility is spread over a longer period of time and further into the future, when the time value of money is further discounted. This makes the project cost (net of offsetting revenue from energy sales) appear lower, so that the calculation does not reasonably reflect the actual costs of the project.

9 Q25. Can you explain how extending the debt term beyond the term of the PPA can make 10 the project costs appear materially lower than they actually are?

11 A25. Yes. The basic idea can be most easily explained by considering a simpler, commonplace 12 debt example, such as a homeowner's mortgage. Imagine that a prospective new 13 homeowner wishes to take out a mortgage in an amount of \$100,000. Let us further assume 14 the cost of that debt (that is, the interest rate on the mortgage) is 4.5% per year, which is 15 the assumed cost of debt for the offshore wind reference facility. These two simple 16 assumptions will suffice to illustrate the material impact of changing the debt term.

Specifically, if the debt term on the mortgage is 20 years, the homeowner would need to spend \$633 per month or \$7,596 per year to make its mortgage payments. However, if the mortgage term is extended to 30 years, the same debt repayment is spread out over time, and its payments will be less. Specifically, if the debt term on the mortgage is now assumed to be 30 years, the same homeowner would need to spend only \$507 per month or \$6,084 per year to make its mortgage payments. Because the debt repayments are stretched out over a longer term, a lower level of income (that is, capacity payments) will enable the

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homeowner to invest in (that is, to afford) the same house.

Of course, this is a simple example, but the general point applies to the homeowner and to large debt-financed capital investments like offshore wind projects. This example simply illustrates that assuming a longer debt term will substantially reduce the monthly costs that a homeowner or developer will incur to finance a new home or new generating facility. For the offshore wind facility, this means that a longer debt term would require less annual capacity market revenue to be viable – and would therefore have a lower ORTP value.

8 This simple example ignores additional considerations, such as taxes and depreciation, 9 which would affect the cost of debt. Even without those additional considerations, the 10 simple point here applies. Assuming an unrealistically long debt term – that is, a term 11 greater than the PPA term – will produce an unrealistically low ORTP value.

Q26. Is the 20-year assumed debt term consistent with similar studies conducted in other regions?

A26. Yes. This assumption is consistent with a recent FERC directive to PJM regarding the calculation of default Minimum Offer Price Rule ("MOPR") offer floors, which serve a similar role to the ORTP, based on an assumed 20-year project life for various resource types.⁹ 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."¹⁰ FERC concluded that "it is

¹⁰ Id.

⁹ Calpine Corporation v. PJM Interconnection, L.L.C., 169 FERC ¶ 61,239 (2019) at P 153.

1 reasonable to maintain these basic financial assumptions for default offer price floors in 2 the capacity market to ensure resource offers are evaluated on a comparable basis."¹¹ 3 While the quoted language above uses the phrase "asset life", it would not be appropriate 4 to assume a debt term in excess of the life of the asset–*i.e.*, when it will operate to produce 5 revenue – and therefore, I view the assumption of a 20-year debt term as consistent with 6 the 20-year asset life guidance from the aforementioned proceedings.

- Q27. Let's now turn to the second of the three modeling horizon considerations, which is
 the facility's expected physical life. What is the commonly accepted definition of
 physical life for a generating facility?
- A27. The facility's expected physical life represents how long the facility is expected to function
 assuming prudent operating and maintenance practices.

12 Q28. What did you assume for a physical life of the offshore wind facility?

13 A28. We assumed a 20-year physical life for the offshore wind facility. We recognize the 14 considerable uncertainty regarding the offshore wind physical service life, as there are only 15 two small offshore wind facilities operating in U.S. waters. One of these is the new 30 16 MW Block Island offshore wind facility operating off the coast of Rhode Island. Since 17 this facility has only been operating for approximately four years, its physical life may not 18 be known for two decades. It is also located considerably closer to shore than other planned 19 facilities in the New England offshore wind lease areas, which may impact its physical life. 20 While there are similarly sized offshore wind facilities in Europe that have been operating 21 for a longer period of time, the physical life of these facilities will not be known for some

¹¹ *Id*.

time, making any assumption around the physical life of new offshore wind facilities
 uncertain.

3 Furthermore, if the owner/operator of the offshore wind facility sought to operate the 4 facility beyond 20 years, it is reasonable to assume that the facility may need major capital 5 expenses to continue operating reliably in New England's marine environment. In the face of such uncertainties, it would be speculative to assume today that the facility would be 6 7 able to operate beyond 20 years without significant additional capital investment at a future 8 date, as the facility ages. Estimating those capital expenditures up front, for purposes of 9 determining the ORTP, would require significant speculation, in particular given the dearth 10 of data on the physical life of large-scale wind facilities.

11 Conversely, an expected 20-year physical life is a reasonable, conservative assumption for 12 offshore wind, despite the difficulties of operating a generation facility in a marine 13 environment, because there is a PPA for that term. It is reasonable to expect the developer 14 will design the facility so that it can operate and receive the revenues for the contract term. 15 Estimating a physical life that goes beyond that 20-year period would require significant 16 speculation.

17 Q29. Turning now to the third consideration in financial horizon modeling, what is the 18 commonly accepted definition of the expected operating life for a generating facility? 19 A29. A generating facility's expected operating life is generally defined as the time period over 20 which the facility is expected to be profitable, considering market and technological 21 obsolescence. We interpret operating life to correspond with another commonly used term 1

in this context, "asset life," and therefore use those two terms synonymously.

2 Q30. What did you assume for an asset life of the offshore wind facility?

3 We assumed a 20 year asset life, consistent with Market Rule 1 Section III.A.21.2(b) and A30. 4 developed our analysis consistent with this ISO Tariff requirement. This means the 5 expected physical life and expected asset life assumptions are consistent, at 20 years, with the term of the assumed 20-year PPA for the facility. While it possible the facility will 6 7 generate sufficient revenues beyond that 20-year period, those revenues are at best 8 speculative, and the facility's overall financial viability in this period is exceedingly 9 difficult to estimate given the lack of data available on the expenditures that would be necessary to keep the facility operational in these later years. 10

11 Q31. How has FERC addressed the issue of debt, physical and asset lives?

12 A31. FERC has recognized these uncertainties generally in modeling the life of new projects for 13 purposes of administering capacity markets and has accepted a 20-year asset life 14 assumption in the PJM calculation of a MOPR for an offshore wind facility. In considering 15 this issue, the FERC stated:

16 We also agree with PJM that default MOPR values should maintain the 17 same basic financial assumptions, such as the 20-year asset life, across 18 resource types. The Commission has previously determined that 19 standardized inputs are a simplifying tool appropriate for determining default offer price floors, and we reaffirm that it is reasonable to maintain 20 21 these basic financial assumptions for default offer price floors in the 22 capacity market to ensure resource offers are evaluated on a comparable 23 basis. Therefore, we find 20 years to be an appropriately conservative 24 estimate.12 25

¹² Calpine Corporation v. PJM Interconnection, L.L.C., 169 FERC ¶ 61,239 (2019) at P 153.

1 We have proceeded consistent with that FERC precedent. In particular, we assume the 2 debt amortization horizon, expected physical life, and expected operating life of the facility 3 would be 20 years.

4

Q32. Please summarize your assumptions.

5 A32. For the reasons explained above, the financial analysis and ultimate determination of an 6 ORTP value for the offshore wind facility assumes a debt term of 20 years, and a physical 7 and operating (asset) life of 20 years, from the year in which it commences commercial 8 operation. The FERC has acknowledged the complex nature of this assumption, and the 9 necessity of exercising some level of professional judgement in determining reasonable 10 debt and asset life assumptions. For the reasons described above, the 20-year life 11 assumptions present a reasonable, objective basis, being aligned with the term of recent 12 public PPAs for new offshore wind projects in New England, for the determination of an 13 ORTP value for a new offshore wind facility. Further, as FERC recently recognized in 14 accepting 20-year benchmarks for PJM, "[r]apid changes in market conditions and 15 generation technology" could make assumptions of longer financial horizons overly optimistic.¹³ 16

17

4. <u>ITC MODELING FOR OFFSHORE WIND</u>

Q33. Given the recent tax law changes in late December 2020 that you noted earlier, please summarize your ITC assumptions for the modeled offshore wind facility.

A33. In December of 2020, Congress passed the 2021 Appropriations Act, providing for, among
 other things, an extension of the ITC for renewable generating resources, including

¹³ Calpine Corporation v. PJM Interconnection, L.L.C., 169 FERC ¶ 61,239 (2019) at P 153 fn 301.

1 offshore wind facilities. The 2021 Appropriations Act provided for an ITC of 30% for an 2 offshore wind facility placed in service in 2025. Because this tax law could have a 3 significant impact on costs for eligible resources planning to participate in FCA 16, we 4 have incorporated this ITC assumption into the DCF and our analysis of the appropriate 5 ORTP value for offshore wind for FCA 16.

6 Q34. How is the ITC accounted for in the DCF model?

7 A34. The ITC for renewable energy resources affects several different elements of financing, 8 and financial modeling, of a renewable energy generation project. For the offshore wind 9 model, the ITC is used in four different calculations in the DCF: i) to reduce the income 10 tax burden in the first year of operation; ii) to calculate the amount of "bonus" depreciation that can be taken in the first year the facility is placed in service; iii) to calculate the 11 12 depreciable basis upon which the facility's accelerated depreciation schedule is applied (known as the Modified Accelerated Cost Recovery System ("MACRS") schedule); and 13 14 (iv) to determine whether, and how much, the ITC reduces the depreciable basis (in step 15 (iii)) that needs to be written off as terminal value at the end of the analysis. This terminal value is treated as a reduction to the cash flow at the end of the investment horizon. 16

Q35. Could you please elaborate briefly on those calculations, with reference to the DCF model you employed for this purpose?

A35. Certainly. In simple terms, the ITC is a tax provision that reduces the income tax burden of the offshore wind facility. Under tax regulations and in the DCF model we employed for this purpose, the ITC is used to adjust the depreciable basis of the facility. In accordance with Internal Revenue Service ("IRS") regulations, one half of the ITC is subtracted from the depreciable basis of the plant. In addition, the ITC affects another

aspect of this calculation, related to that depreciable basis. Specifically, the 40% "bonus" 1 2 deprecation (provided under IRS regulations) is then applied to the ITC-adjusted 3 depreciable cost of the installed facility to calculate a bonus depreciation amount, in dollar 4 terms; that amount is subtracted from the ITC-reduced plant basis to arrive at a beginning 5 plant value over which to depreciate the facility. (This is the second calculation we note 6 in our response to question 34, above.) That beginning plant value (net of the ITC and 7 bonus depreciation), is then depreciated over a five-year MACRS schedule. (The third 8 calculation noted above.) Last, the undepreciated amount of the depreciable basis of the 9 facility is then treated as terminal value and written off at the end of the 20-year asset life.

10 (This is the final calculation noted in our response to question 34 above.)

11 Q36. How was the offshore wind facility assumed to monetize the ITC?

12 A36. To fully monetize – that is, benefit from – the value of the ITC, either the project owner, 13 its corporate parent(s), or a partnering tax entity (or some combination thereof), needs to 14 have sufficient tax liabilities to make full use of the offshore wind project ITC credits. It 15 was assumed that the project sponsor could monetize this new ITC benefit in developing 16 the project, based on an assumption that the developers of new offshore wind projects in New England are large, national or international corporations (e.g. Copenhagen 17 18 Infrastructure Partners, Ørsted, Avangrid, and Eversource). Such corporations have large 19 balance sheets representing a variety of investments that could allow them to monetize 20 such tax benefits. The assumption utilized in the ORTP analysis, that the current 30% ITC 21 benefit can be monetized, is a plausible and reasonable assumption for a generating facility

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that is being developed by large corporations.

Q37. Is the modeling of the ITC in this ORTP calculation consistent with FERC's decision on modeling tax credits in the prior 2017 ISO Net CONE/ORTP proceeding?

4 A37. Yes. In the 2017 recalculation that we performed for the ISO and that the FERC accepted, 5 the ORTP calculation involved the use of a PTC for onshore wind.¹⁴ In its filing, the ISO asserted that the inclusion of the PTC was appropriate, as the PTC was then in effect and 6 7 available as a source of non-capacity revenue to qualifying resources. The ISO went on to 8 state further that there is no ISO Tariff requirement that the PTC must be both available 9 and shown to be 100 percent utilized by all onshore wind resource developers in order for 10 that credit to be reflected in the updated ORTP value for onshore wind resources.¹⁵ In the 11 FERC Order accepting the ORTP values, the FERC found that the inclusion of the full PTC 12 was just and reasonable.¹⁶ The same underlying rationale, and conclusion, is applicable to 13 the ITC included in this ORTP calculation.

14 Q38. How impactful is the ITC in the determination of the ORTP?

A38. The ITC substantially decreases the total cost of the project to the developer. In simple terms, the current ITC rate of 30% partially offsets a significant portion of the capital expense of developing the offshore wind project, lowers the overall capital costs used in the DCF.

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However, the ORTP analysis is intended to determine the minimum capacity revenue

¹⁴ See ISO New England Inc., 161 FERC ¶ 61,035 (2017).

¹⁵ Id.; see also Motion For Leave to Answer and Answer of ISO New England Inc., Docket No. ER17-795, p. 7 (March 21, 2017)

¹⁶ See ISONew England Inc., 161 FERC ¶ 61,035 (2017).

1 required to make the project "whole" - that is, to cover its after-tax weighted-average cost 2 of capital per MW of its FCM qualified capacity ("QC"). And the project's QC is (slightly) 3 less than one half of its 800 MW installed capacity (the OC value is discussed further 4 below, in Section 5 of this testimony). This means that the benefit of the ITC on a per MW 5 basis of installed capacity is more than double the ITC benefit on a per MW basis of 6 qualified capacity. After the ITC is applied, the minimum capacity revenue to make the 7 project "whole" is approximately \$8/kW-month on an installed capacity basis, but much 8 higher, at approximately \$18/kW-month, on a QC basis. This difference occurs because, 9 as noted above, the project's QC is (slightly) less than one half of its 800 MW installed 10 capacity.

11 To further demonstrate how impactful the ITC provisions are, we have performed this same 12 ORTP calculation but as it would be applied in a world where, hypothetically (and counter 13 to fact), there is no ITC for offshore wind. In that hypothetical scenario, this same project's 14 minimum capacity revenue value is approximately \$20/kW-month on an installed capacity 15 basis but much higher, at approximately \$44/kW-month, on a QC basis.

Obviously, the \$18/kW-mo. minimum capacity revenue on a QC basis with the new ITC provisions is much lower than the \$44/kW-mo. value on a qualified basis that would apply in the absence of the ITC. In effect, the ITC reduces the minimum capacity revenue dramatically, from approximately \$44/kW-month to approximately \$18/kW-month.

20

5. ESTIMATED ORTP VALUES FOR OFFSHORE WIND

21 Q39. Please summarize the balance of the ORTP calculation for offshore wind.

A39. Having previously explained the financial modeling horizon assumptions and ITC
 treatment, I will now turn to the remaining components of the ORTP calculation for the

2 20-year amortization period. These include: i) the technical specifications; ii) the installed 2 capital costs and operating costs; iii) the expected market revenues for the offshore wind 3 facility, which include energy revenues and ancillary services revenues (net of production 4 costs), REC revenues, and Pay for Performance ("PFP") revenues; and iv) the levelized 5 revenue requirement that reflects the break-even contribution required from the capacity 6 market to achieve a net present value of zero, given its assumed capital structure and 7 required rate of return.

8 Q40. Please describe the development of the technical specifications, installed capital costs 9 and operating costs.

A40. Mott MacDonald first selected a location for the offshore wind facility that considered access to onshore transmission infrastructure, the ability of the transmission system to accommodate the offshore wind output with minimal need for transmission system upgrades, and the availability of offshore site leases. Mott MacDonald selected a Massachusetts Offshore Wind Lease area interconnected at Brayton Point Station in Somerset, MA. This evaluation is explained in additional detail in Mott MacDonald's companion report included with the ISO's filing.

In calculating an appropriate capital cost for the offshore wind facility, Concentric consulted Mott MacDonald and reviewed publicly available data about offshore wind facility capital costs. The assumed overnight costs for the offshore wind facility were \$4,286 million (2019\$) and \$4,357 million (2025\$) or \$5,446 per kW (2025\$) of installed capacity. This latter value was separately benchmarked against publicly available data, as more fully explained below.

23 Concentric estimated fixed Operating and Maintenance ("O&M") costs for the offshore

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wind unit based on a long-term service agreement ("LTSA") estimate provided by Mott
MacDonald. The LTSA includes labor, materials, contract services, and associated costs
with an estimated cost of \$7.34/kW-month (2025\$). Ongoing maintenance costs were
assumed to be approximately \$1,000/MW-year (2025\$) based on Mott MacDonald's
experience in the expected level of capital investment for power generation facilities over
a 20-year time horizon.

7 We assumed that the leasing area of 75,600 acres would be leased at an annual cost of 8 approximately \$530,000 or \$7/acre (in 2025\$), based a review of publicly available site 9 leasing agreements. Offshore wind lease areas are typically leased by the U.S. Department 10 of the Interior's Bureau of Ocean Energy Management to the developer. While a limited 11 number of these leases have been executed, Concentric reviewed several leases to estimate the lease costs for offshore wind. Based on a review of the leases for Vineyard Wind and 12 13 Bay State Wind, Concentric estimated the average per-MW lease cost to be \$665/MW of installed capacity. On a per acre basis, that is approximately \$7/acre. 14

We determined that a property tax rate of 1% based on a payment in lieu of taxes agreement was a reasonable representation of an expected local tax rate. This rate was applied to an average of net plant values on an annual basis. Based on this assumed rate, the property taxes for the offshore wind facility were estimated at approximately \$4MM per year (2025\$), or \$5.06/kW-year.

Insurance costs were assumed to be 0.3% of installed costs, consistent with the assumption
for other resources included in the ORTP analysis. Annual insurance costs were estimated

1 to be approximately \$13.6MM in 2025 dollars.

Based on these assumptions, the levelized fixed O&M cost of the wind facility over its 20year life is \$110.87/kW-year, or \$9.24/kW-month. (2025\$).

4 Q41.

5

Please provide the financial assumptions used to calculate an ORTP for the offshore wind facility.

A41. The financial assumptions used for the offshore wind facility were based on the same cost
of debt and equity used for the ORTP calculations for other technologies. I will provide a
brief summary of those assumptions here, and additional detail is provided in Section 7.D.
of the CEA Report.

10 The calculation of an offshore wind ORTP requires a real discount rate to translate 11 uncertain future cash-flows into a levelized revenue requirement. The ISO Tariff 12 provisions for calculating ORTPs specifies that the ORTP modeling should assume a PPA 13 contract is in place for the project, which impacts the appropriate assumptions for the cost 14 of debt and equity.¹⁷ First, we adjusted the cost of debt that was assumed in the CONE 15 calculation to more closely reflect the generic corporate debt of a higher-rated company. 16 Instead of a cost of debt of 6.0% assumed for the CONE study, which assumes a premium 17 on top of recent debt issuances for Independent Power Producers ("IPPs") and assumes a 18 premium on top of B- and BB-rated corporate bond yields, we assumed a lower cost of 19 debt of 4.5% for the ORTP calculations, including the offshore wind ORTP calculation. 20 That assumption does not assume a premium and is more in line with the average costs of

¹⁷ ISO Tariff Section III.A.21.1.2.(b) ("The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted A verage Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties").

debt for a company with a BB rating. It is also in line with recent debt issuances for IPP
 peer companies.

3 Second, we calculated a target Return on Equity ("ROE") to reflect contracted revenues 4 according to the PPA assumption specified in the ISO Tariff.¹⁸ We estimated an ROE using 5 a Capital Asset Pricing Model ("CAPM"), equal to a risk-free rate plus a risk premium given the expected risk premium of the overall market, multiplied by the company's "beta" 6 7 that reflects how its risk co-varies with the market. Consistent with the approach used to 8 calculate beta in the CONE recalculation, we reviewed estimates from Blue Chip, Value 9 Line, Ibbotson, and Bloomberg for the inputs to the CAPM. We calculated an ROE at the 10 low end of the competitive range using a forward-looking estimate of beta from those 11 sources, with a resulting target return on equity of 11.0%.

12 The assumed capital structure for the ORTP calculations is 60/40 (Debt/Equity). This 13 assumes slightly higher leverage than that assumed for the CONE calculation, favoring a 14 lower required ROE because the resources modeled for ORTP purposes are assumed to 15 face lower risk due to their 20-year PPA agreements for energy (that is, a PPA was not 16 assumed in modeling Net CONE).

A summary of the financial assumptions on which the ORTP calculations are based isshown in the below.

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

Offshore Wind Facility Financial Assumptions

Q42. Please describe how the expected market revenues for the offshore wind facility were calculated.

A42. The approach used to calculate expected energy and ancillary services ("E&AS") revenues
for <u>offshore</u> wind is similar to the approach used to calculate expected E&AS revenues for
<u>on-shore</u> wind, as explain in Section 7.I.iv of the CEA Report. We refer to these as
"revenue offsets" because they offset, in part, the need for capacity revenue to make the
project financially viable.

9 At a high level, ORTP expected revenue offsets for the offshore wind facility come from 10 one or more of the following potential revenue streams: i) E&AS revenues; ii) PFP 11 revenues; and iii) REC revenues. These revenue streams were developed with simplified 12 dispatch models that used historical energy prices during the 2017-2019 period that were 13 adjusted with an energy/reserve scarcity adjustment.

For the calculation of estimated E&AS revenues, the offshore wind facility is assumed to schedule all of its megawatt-hours ("MWh") of energy output into the ISO-administered energy market as a price taker, and is therefore not dispatched for (that is, designated to provide) ancillary services. The output assumed to be scheduled in the energy market is based on data 2019 wind and power time series modeling study of wind plants performed for ISO-NE.¹⁹ Thus, its total E&AS revenue is comprised of only energy market revenue,
 as its ancillary services revenue is modeled as zero. This is consistent with how onshore
 wind resources are modeled, and consistent with how wind resources participate in the
 ISO-NE markets generally.

5 Similar to the CONE calculation, estimated energy revenues from high-price "scarcity" periods during real-time reserve shortages were added as a separate line to the financial 6 7 model, outside of the ORTP dispatch models. The energy/reserves scarcity revenue adder 8 for the ORTP units, including the offshore wind unit, assumed 7.4 scarcity hours annually, 9 which is based on the ISO's modeling for their system given expected prevailing excess 10 supply conditions. This annual scarcity hours estimate is lower than the 11.3 scarcity hours 11 assumed in the Net CONE study for the energy/reserve scarcity adder, as the latter was 12 based on the system's projected performance under long-term equilibrium (or 'at criterion') 13 conditions.

14 For the offshore wind facility, the energy/reserve scarcity unit adder is shown below.

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Offshore Wind Facility Energy/Scarcity Adder

	Availability Factor	Adjustment \$/kW-mo.
Offshore Wind	30.34%	0.19

¹⁹ New units would not have operational data, therefore we used 2019 offshore wind data from the 2020 DNV ISO New England Wind Data Series, rev.2, for this calculation. DNV is an advisor on, and developer of, renewable energy resources, including offshore wind resources, and provides analysis and data associated with these resource types. See: <u>https://www.iso-ne.com/static-assets/documents/2020/09/2020 iso ne_variable_energy_resource_ver_data_series_2000_2019_rev3.zip</u> for the most recent version of this data.

1 The 30.34% availability factor is based on the seasonal availability of the resource during 2 scarcity conditions. This reflects the facility's expected energy production during those 3 hours²⁰ (as a share of its QC), and is the same input used to calculate the facility's PFP 4 revenue.

5 Q43. Please describe how the expected PFP revenue for the offshore wind facility was 6 calculated.

A43. PFP revenues for the offshore wind unit were calculated in the same manner as the CONE
units, but with values specific to ORTP calculations. For the PFP revenues calculation, as
noted above and further explained in the CEA Report at pages 70-71 and 87, the estimated
scarcity hours ("H") were 7.4 annually and the system's balancing ratio ("Br") was
estimated to be 0.816 percent for all ORTP technology types.

As with the ORTP calculation for other intermittent resources (e.g., onshore wind), 12 13 estimating the expected performance during scarcity hours ("H") for the offshore wind technology requires a different set of assumptions than using a forced-outage rate (which 14 15 is applicable to non-intermittent generating facilities). To estimate the average annual 16 performance of the offshore wind unit during scarcity hours, or "A", we assumed that the 17 unit's average performance during scarcity hours would, on average, be equal to the 18 forecasted generation during Summer Intermittent Reliability Hours and Winter 19 Intermittent Reliability Hours. These summer/winter performance values are then weighted 20 by the expected amount of seasonal scarcity hours. Peak load scarcity hours are assumed

²⁰ There are three categories of scarcity modeled: 6.2 peak load hours, which occur during summer periods; 0.4 hours modeled for winter periods; and 0.8 hours of expected transient events. The offshore wind unit availability reflects a weighted average of the unit performance during those hours.

to occur in the summer, transient scarcity hours are assumed to occur randomly throughout the year, and winter scarcity hours are assumed to occur in the winter. The weighted performance values are shown in the table below. This overall approach is analogous to that employed in the ORTP analysis for onshore wind resources, as described at page 87 of the CEA Report.²¹

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	NAMEPLATE (MW)		Winter Performance (MW)	Scarcity Type Weighted Performance	Scarcity Weighted [A]
Offshore Wind	800	212.6	451.2	242.7	30.34%

8 Note that, both in concept and in our actual calculations for the ORTP, the value of "A" 9 for purposes of estimating PFP revenue (as shown in the table immediately above) is the 10 same as the value of "A" used for estimating the resource's energy scarcity revenue (as 11 shown the preceding table in Answer A42. That is, the offshore wind facility is assumed 12 to have energy output of 30.34% of its QC during Capacity Scarcity Conditions, on an 13 annual average basis.

In addition to calculating the expected performance value "A", the expected PFP revenues earned by the intermittent units needs to account for the seasonal variation in the Capacity Supply Obligation ("CSO") that these units receive. Assuming that the unit receives a seasonal CSO equal to its QC MW, the percent of nameplate having CSO is applied by

²¹ See CEA Report at p. 87 for the application of this methodology to the onshore wind technology.

weighting the expected CSO awarded to the offshore wind facility during the summer and
 winter reliability hour periods.

Additional information on the calculation of these values is explained in the CEA Report
on pages 86 and 87.

5 Q44. Please describe how the REC revenues for the offshore wind resource were calculated.

6 A44. Similar to the calculation of REC revenues for the on-shore wind facility as described in 7 the CEA Report²², REC revenues for the offshore wind facility were calculated as the 8 product of an estimated REC price and the unit's size and annual capacity factor. To 9 estimate the REC price, Concentric relied on historical price data for MA Class I REC 10 indices for the 2016 - 2020 vintages. Concentric calculated the average price for each REC 11 vintage based on all trades available at the time of the analysis. Concentric then averaged 12 those five estimates (normalized to 2019\$) to produce a single REC price and then escalated that average to 2025 dollars. The resulting average REC price was \$29.32/MWh. 13 14 The capacity factor is based on the output calculated for E&AS purposes as described 15 above for an 800MW offshore wind resource.

16 Q45. How did you calculate the QC for the offshore wind facility?

A45. ORTPs are calculated in \$/kW-month terms, and the relevant "kW" is the QC of the facility
 - that is, the maximum amount of capacity that the resource would be qualified to sell in
 the FCM. For intermittent resources generally, and offshore wind facilities specifically,

²² Section 7.I.vi, p. 90.

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the QC is less than its installed capacity.

2 To further explain, this CONE/ORTP study defines "Nameplate Capacity" as the 3 manufacturer's determination of the maximum megawatt output of electricity a generator can produce without exceeding design limits. While this is a value requested in the 4 registration process at the ISO, it is not the resource's QC. The term "Nominal Capacity" 5 6 is defined as the maximum megawatt output of a generator at site specific conditions. 7 Nominal Capacity is used solely to present costs and revenues on a \$/kW-month basis to 8 allow Market Participants to compare these costs and revenues against other publicly 9 available information.

10 The term "Qualified Capacity" is defined as the capacity of the resource expected to 11 participate in the FCM. The QC is used to translate costs and revenue estimates into dollars 12 per QC value figures for purposes of determining Net CONE and ORTP values.

For intermittent resources, the ISO Tariff requires that the QC be based on the median output during summer and winter reliability hours.²³ Using the dispatch models used to calculated E&AS offsets, ISO-NE calculated the median output in the 2019²⁴ summer and winter reliability hours (HE 14-18 for summer, and HE 18-19 for winter). The results were then weighted by four months summer/eight months winter to get an annual QC. The results are summarized in the table below and are properly measured on a dollars per QC amount per month. The QC is the MW value with which the resource will participate in

²³ ISO Tariff Section III.13.1.2.2.2.

²⁴ New units would not have operational data on which to base this calculation, so it was assumed that the ISO's systemplanning will rely on the most recent market data available when qualifying new resources. Therefore, 2019 data from the 2020 DNV ISO New England Wind Data Series, rev.2, was used for this calculation. See https://www.iso-ne.com/static-assets/documents/2020/02/a7b wind power time series dnvgl.pdf.

and earn revenues from the FCA. Therefore, the ORTP uses this value to determine the "missing money" or amount of revenues a resource will require from the capacity market, on a per-kW-month basis, to be economically viable.

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	Nominal Capacity (MW)	Summer QC (MW)	Winter QC (MW)	Annual Weighted QC (MW)	Qualified Capacity as % of Nominal Capacity	Final Qualified Capacity (MW)
Offshore Wind	800	212.63	451.18	371.66	46.5%	371.66

5 Q46. Please summarize the results of your calculation for the offshore wind ORTP.

6 A46. Employing the calculation described above, the ORTP for the offshore wind facility would 7 be \$17.948/kW-month.²⁵ This is the estimate of the minimum capacity revenue needed for 8 the reference offshore wind facility to be financially viable in the absence of any out-of-9 market revenue sources, and therefore would serve as the ORTP for offshore wind were 10 the value not above the FCA 16 auction starting price. This value accounts for all the 11 assumptions and calculations addressed in this testimony, the CEA Report, the CONE 12 Addendum, the ORTP Addendum and the Mott MacDonald Report.

A summary of the principal inputs into this calculation of the ORTP value for the offshore wind resource is shown below. Please note that, as the ISO's Tariff is structured, because the estimated \$17.948/kW-month value is above the FCA starting price, no ORTP value for offshore wind is specified in the ISO Tariff.

²⁵ I will note that this value is significantly impacted by the ITC. Without the ITC, the ORTP for the offshore wind facility would be \$44.421/kW-month.

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NOMINAL INSTALLED CAPACITY (MW)	QUALIFIED CAPACITY (MW)	INSTALLED COST 2019\$/KW	REAL ATWACC	GROSS CONE (2025\$/KW- MO.)	REVENUE OFFSETS (2025\$/KW- MO,)	ORTP (2025\$/kW-mo. INSTALLED)	ORTP (2025\$/kW· MO. QUALIFIED)
800	372	\$5 <i>,</i> 358	4.3%	\$33.833	\$25.495	\$8.338	\$17.948

Offshore Wind Facility Summary

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6. CAPITAL COST BENCHMARKING

4 Q47. Did you benchmark the offshore wind capital costs developed by Mott MacDonald 5 against publicly available information?

6 A47. Yes. We reviewed publicly available information on offshore wind projects currently in 7 development, including publicly available information published by the U.S. Energy 8 Information Administration ("EIA"), the Environmental Protection Agency ("EPA"), the 9 Department of Energy ("DOE"), the National Renewable Energy Laboratory ("NREL"), 10 and the New York State Energy Research and Development Authority ("NYSERDA"). In 11 addition, we reviewed several sources of information on global offshore wind installations, 12 including European projects where publicly available estimates of construction costs were 13 available.

14 Q48. How would you categorize the type of benchmarking studies available?

15 A48. There is a plethora of benchmarking data available, and careful analysis was required to 16 determine the source and scope of the data reported. In our review, we found a limited 17 number of studies that estimated capital costs on a regional basis, while various other 18 studies reported capital costs reflecting more general national or global estimates. Capital 19 costs can vary significantly based upon location. Therefore, the regional studies provide 20 the most pertinent benchmarking costs as they reflect costs specific to the New England or

1 Northeast region.

Further, the source of data used to develop the studies varied. The vast majority were based upon installed costs of commissioned wind farms, mainly in Europe and China where the bulk of operating wind farms are located.

5 Of all these publicly available sources, the only study we identified conducted by an 6 engineering firm that clearly used a "bottom-up" cost estimation method was produced by 7 the EIA. The capital cost estimates contained in the EIA study were supported by Sargent 8 & Lundy ("S&L"), a reputable engineering firm, and was based on a bottom-up analysis, 9 consistent with the approach taken in our ORTP study.

Q49. What was the range of estimates included in the regional bottom-up engineering costbased studies?

12 A49. The regional capital cost estimates for New England ranged from \$5,600/kW to \$6,494/kW 13 (in 2023\$). These capital costs are higher than the \$5,510/kW (2023\$) estimated by Mott 14 MacDonald. The table below provides summarizes the study, published year, source of the 15 data, and the offshore wind unit capital cost. The two external regional estimates for New 16 England are shown in the first two rows of the table.

Report / Reference	Year Published	Underlying Source of Data	Capital Cost (used as Concentric benchmark)	Capital Cost Escalated to 2023\$*
EIA: Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2021	2021	Capital costs were based on engineering estimates developed by an external consultant (Sargent & Lundy) and include both a new technology uncertainty adjustment and locational (New England) adjustment	\$6,360 ²⁶ (2020\$)	\$6,494
EIA: Cost of New Generating Technologies, Annual Energy Outlook 2020	2020	Capital costs were based on engineering estimates developed by an external consultant (Sargent & Lundy) and include both a new technology uncertainty adjustment and locational (New England) adjustment	\$5,446 ²⁷ (2019\$)	\$5,600
PJM: Recalculation of the Default MOPR Floor Offer Prices	2020	Capital costs were based on engineering estimates developed by an external consultant (Sargent & Lundy), and <u>does not include</u> any new technology uncertainty adjustment or any locational adjustment applicable to New England	\$4,375 ²⁸ (2019\$)	\$4,499
ISO-NE: Mott MacDonald Offshore Wind ORTP Report	2020	Capital costs were based on engineering estimates developed by Mott MacDonald (see Mott MacDonald Report, Table 4.1) and are specific to New England	\$5,358 (2019\$)	\$5,510

Offshore Wind Regional Bottom-up Study Summary

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engineering analysis performed by S&L for the EIA. This highlights the scarce nature of

It is important to note that the first three studies in the table above are based on the same

²⁶ See US EIA, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2021 (released February 2021), Table 2, column 7 (showing values for ISO-NE and labeled 'ISNE'); available at <u>https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf</u>.

²⁷ See U.S. EIA, Assumptions to the Annual Energy Outlook 2020: Electricity Market Module (released January 2020), Table 4, column 7 (showing values for ISO-NE and labeled 'ISNE'), available at https://www.eia.gov/outlooks/archive/aeo20/assumptions/pdf/electricity.pdf.

²⁸ PJM, Default MOPR Floor Offer Prices for New Generation Capacity Resources, PJM presentation to the Market Implementation Committee (March 11, 2020), p. 4; *available at* <u>https://www.pjm.com/-</u>/<u>/media/committees-groups/committees/mic/2020/20200311/20200311-item-06c-default-mopr-cone.ashx</u>; the primary source for this value is Sargent & Lundy, Capital Cost Study: Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, Prepared for U.S. EIA, Final Report (released December 2019), Table 22-1, p. 162; *available at* <u>https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf</u>.

information on offshore wind capital costs for U.S. installations. Other than our own, the
 study commissioned by the EIA and performed by S&L is the most recent and only
 transparent, detailed analysis of the cost to install an offshore wind facility that accounts
 for locational differences that have a material impact on capital costs.

5 Q50. What are the reasons why the bottom-up estimate performed by S&L for the EIA 6 would vary from that performed by Mott MacDonald?

7 The 2021 EIA study's final estimate of \$6,360/kW-month (in 2020\$) includes a 25% A50. 8 adjustment for the uncertainties associated with technologies that are the first of their kind 9 to be developed, at large scale, in the U.S, which was not included in the Mott MacDonald 10 bottoms-up estimate. This adjustment is also included in the EIA's prior (2020) offshore 11 wind estimate of \$5,446 (in 2019\$), as shown in row 2 of the table above. This type of adjustment is appropriate, conceptually, as the large offshore wind projects in New 12 13 England (to which the ORTP will apply) will be the first of their kind to be developed at 14 this large scale in the US.

- Both the 2021 and the 2020 EIA estimates in rows 1 and 2 of the table (respectively) also include a locational adjustment for construction and development in New England, which S&L determined would have higher costs than their "base" capital cost estimate of \$4,375/kW.²⁹ For that reason, the base capital cost estimate developed by S&L – which is not adjusted for a New England location – is less useful for our benchmarking effort.
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Note further that, as explained in the table, the values reported in row 3 for the PJM

²⁹ Sargent & Lundy, Capital Cost Study: Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, Prepared for U.S. Energy Information Administration, Final Report (released December 2019), Table 22-1, p. 162; available at <u>https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf</u>.

application do not include the EIA's 25% adjustment for the uncertainties associated with technologies that are the first of a kind to be developed in the U.S. Nor does it include any location adjustment for construction and development costs in New England. We include the PJM value in the table above solely for completeness; however, because of those cost factor omissions, we consider the S&L "base case" estimate adopted in PJM to be not directly applicable for benchmarking the capital costs of offshore wind development in New England.

Q51. Are there any reasons why the offshore wind capital cost estimates derived from the
S&L engineering-based study – and the S&L "base" capital cost in particular – would
be too *low* for New England?

11 A51. Yes. On close review, the S&L study assumed that the offshore wind facility in their 12 bottom-up engineering-cost analysis would be sited only 30 miles offshore. This is half the 60-mile cabling distance appropriate for the Massachusetts Offshore Wind Lease areas, 13 14 as detailed in the Mott MacDonald Report, Section 4.3. As noted previously, this 15 substantially reduces the capital costs associated with the submarine cabling and 16 assumptions in the S&L estimate, relative to the applicable scope of work evaluated by Mott MacDonald. We highlight this because it is a source of variation that would tend to 17 18 make S&L's "base" estimate too low, relative to the actual scope of work for an offshore 19 wind facility developed off the seacoast of Massachusetts.

20 Q52. What do you conclude from the most recent studies produced by the EIA, in 2020 and
21 2021?

A52. The EIA's 2020 and 2021 studies provides offshore wind capital cost estimates specific to
 New England, and to other regions. For the New England region, the capital cost estimates

range are, after escalation to 2023 dollars, \$5,600/kW and \$6,494/kW respectively. These are comparable to the Mott MacDonald estimate of \$5,446/kW (in 2023 \$) for offshore wind development applicable to New England. These external benchmark estimates are based on work performed by S&L, and represent an independent, bottom-up engineeringeconomic analysis of the estimated capital costs for an offshore wind facility. In that regard, they are the only other independent, bottom-up public analysis of the cost of installation of an offshore wind facility in U.S. waters.

8 Q53. What do you conclude from the regional bottom-up engineering cost-based studies 9 summarized in the table above?

10 A53. The regional bottom-up engineering cost-based studies provide a corroborating, 11 independent benchmark of offshore wind capital costs for New England. These studies 12 represent costs that more closely resemble the costs that may be expected to be incurred 13 for an offshore wind project located in the Northeast.

14 Q54. Did you review other offshore wind capital cost estimate studies as well?

15 A54. Yes. Concentric reviewed studies using data from NREL, as well as studies produced by 16 NYSERDA, the International Renewable Energy Agency ("IRENA"), the U.S. 17 Environmental Protection Agency, Lazard, and a report from Dominion Energy that was 18 included as part of a 2020 Integrated Resource Plan filed with the Commonwealth of 19 Virginia. These reports were relied upon by various proponents of a \$0.000/kW ORTP 20 value for offshore wind during the stakeholder discussions of ISO-NE's proposed ORTP 21 The specific report name, year published, underlying source of data, and updates.

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estimated offshore wind capital costs for these studies are shown in the table below.

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Offshore Wind Other Studies Summary

Report Name	Year Published	Underlying Source of Data	Capital Cost 2019\$
NREL Vineyard Wind PPA Analysis	2019	The capital expenditures (CapEx) of \$3,500/kilowatt (kW) were sourced from Bloomberg New Energy Finance (2018) for the prevailing average CapEx for offshore wind projects in Europe.	\$3,525 ³⁰
DOE: 2018 Offshore Wind Technologies Market Report	2018	Based upon the NREL internal offshore wind database (OWDB). Primary sources of the database noted were: 2018 Offshore Wind Farms Intelligence; 2019 Global Offshore Wind Farms Intelligence; BNEF Renewable Energy Project Database; MAKE Consulting 2018 Global Offshore Wind Power Project DB; and WindEurope 2019 Offshore Wind in Europe: Key trends and statistics 2018 report. The study reports "a capacity-weighted av erage CapEx of \$4,350 in 2018 globally" (pg. 59)	\$4,380 ³¹
NREL: 2020 Annual Technology Baseline	2020	Base cost estimates reflect international projects and are calibrated to correspond to recent cost and technology trends in the US and European offshore wind projects.	\$5,044 ³²
NYSERDA	2020	Proprietary database of the whitepaper authors, Renewables Consulting Group (underlying sources of data not identified)	\$3,155 ³³
IRENA: Renewable Power Generation Costs in 2018	2018	Project data from the IRENA Renewable Cost Database (appears to be mainly installations and commissioned projects in Europe and China)	\$4,800 ³⁴
IRENA: Renewable Power Generation Costs in 2019	2019	Project data from the IRENA Renewable Cost Database	\$3,500 ³⁵
EPA: 2018 IPM Platform	2018	2016 NREL Annual Technology Baseline	\$6,705 ³⁶
Lazard: 2019 LCOE Analysis	2019	Lazard proprietary estimate (underlying sources of data not identified)	\$2,950 ³⁷
Dominion 2020 Integrated Resource Plan	2020	Dominion estimate (underlying sources of data not identified)	\$2,894 ³⁸

³⁰ NREL The Vineyard Wind Power Purchase Agreement: Insights for Estimating Costs of U.S. Offshore Wind Projects, Technical Report, NREL/TP-5000-72981, February 2019, p. 6; *available at* <u>https://www.nrel.gov/docs/fy19osti/72981.pdf</u>.

³¹ US DOE 2018 Offshore Wind Technologies Market Report, p. 59; available at <u>https://www.energy.gov/sites/prod/files/2019/09/f66/2018%20Offshore%20Wind%20Technologies%20Market %20Report.pdf</u>.

³² 2020 Annual Technology Baseline, Offshore Windtab, available at <u>https://atb.nrel.gov/electricity/2020/data.php</u>.

1 The reported values in the table above varied widely. An in-depth review of the data source 2 reveals why: all of the studies rely greatly (or in the case of the Vineyard Wind analysis, 3 exclusively) on global cost data. Therefore, these studies do not provide values that are 4 appropriate for, or applicable to, the U.S. or New England.

5 The most recent NREL Annual Technology Baseline also is sourced heavily from global 6 data, calibrated based on cost trends in both the US and Europe, and is not adjusted for 7 regional cost differences.³⁹ This tool also provided various estimates based on the offshore 8 wind facility water depth and distance from shore; as Mott MacDonald has noted, the 9 location of an offshore installation can have a significant impact on the overall project

³⁵ IRENA Renewable Power Generation Costs in 2019, Figure 4.4; available at <u>https://www.irena.org/publications/2020/Jun/Renewable-Power-Costs-in-2019</u> ("IRENA 2019 Costs").

³³ White Paper on Clean Energy Standard Procurements to Implement New York's Climate Leadership and Community Protection Act, Case 15-E-0302, June 18, 2020, Appendix A, Table 14, p. 29; available at <u>http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0302&submit=Search</u>; (service number 258) ("NYSERDA White Paper").

³⁴ IRENA Renewable Power Generation Costs in 2018, Figure 3.3; available at <u>https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/May/IRENA_Renewable-Power-Generations-Costs-in-2018.pdf</u>.

³⁶ EPA, Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, November 2018, *available at* https://www.epa.gov/airmarkets/documentation-ipm-platform-v6-november-2018-reference-case-all-chapters. The value shown is comprised of the base capital costs for 2023 vintage (build year) as \$4,169, as shown in Table 4-16 (page 4-28); adjusted for the regional cost adjustment factor of 1.068 for "NENGREST", as noted in Table 4-15 (page 4-26); and the short-term capital cost adder of \$1,933 for the "model run" year of 2023 (the expected start of construction for the off-shore wind unit), shown in Table 4-14 (page 4-25). The total of \$6,385 reported in 2016\$ was escalated to 2023\$.

³⁷ Lazard's Levelized Cost of Energy Analysis—Version 13.0, November 2019, p. 17; *available at* <u>https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf</u>.

³⁸ Virginia Electric and Power Company's Report of Its Integrated Resource Plan, Virginia State Corporation Commission Docket No. PUR-2020-00035, Virginia Electric and Power Company 2020 IRP, Appendix 5N – Busbar Assumptions, document page 245; available at <u>https://www.dominionenergy.com/-</u>/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509.

³⁹ Annual Technology Baseline/Technologies/Offshore Wind, "CAPEX estimates are calibrated to correspond to the latest cost and technology trends observed in the U.S. and European offshore wind markets", and "CAPEX reflects typical plants and does not include differences in regional costs associated with labor, materials, taxes, or system requirements." See ATB Electricity Data Overview\Technologies\Offshore Wind, at https://atb.nrel.gov/electricity/2020/index.php?t=ow.

costs.⁴⁰ This is supported by the NREL ATB. For example, installations close to shore
 (35 km, or 22 miles) had estimated capital costs of \$3,666/kW (2019\$), while the estimated
 capital costs for a facility located further from shore (77 km, or approximately 48 miles)
 were \$5,044/kW (2019\$).

5 It is important to note that the DOE values in row 2 in the table above are based on third-6 party sources that relied on global cost estimates, primarily from European projects, as 7 noted in the source description column.

8 Q55. Are the global studies appropriate comparisons for benchmarking the offshore wind 9 capital costs for New England?

10 A55. No. For a true comparison between a U.S. offshore wind project and a European offshore 11 wind project, the scopes of work should be comparable. However, IRENA notes that the 12 scope of work on which these values are based vary widely from country to country. All 13 projects have specific design criteria based on their specific location, technical 14 requirements, local government requirements, safety and environmental requirements, grid 15 interconnection details, etc. These criteria can have a significant impact on capital costs. 16 This is especially true for construction and labor costs from projects in China, which is 17 considered problematic by western offshore wind experts.⁴¹

For example, in some European countries, the cost of the offshore substation and the transmission lines to the point of interconnection is assumed by the utility. Therefore, those costs are excluded from project development costs. For this reason, some European project

⁴⁰ Mott MacDonald Report, Section 4.3.

⁴¹ Mott MacDonald Report, Section 5.2.

costs, depending on the country, need to be adjusted to add interconnection scopes of
 supply and costs before being used as an appropriate benchmark against U.S.-based
 projects.⁴² The offshore substation platform and the submarine export cabling represent
 approximately 25% of Mott MacDonald's total offshore wind capital cost estimate.

5 Another important variable in an offshore wind facility installation is the distance from the offshore substation platform to the point of interconnection. The offshore wind project that 6 7 is the subject of our ORTP analysis is located in a Massachusetts lease area with an 8 interconnection point in Somerset, Massachusetts, which is approximately 60-miles from 9 the substation platform and selected lease area. The assumed distance to shore is impactful on the capital cost estimate for an offshore wind facility and must be specified in order to 10 compare data sources. 43 Most operating European and Chinese installations are located 11 12 much closer to shore, with corresponding lower costs.

One final factor to consider when comparing Chinese and European data is the selfreporting nature of the data by developers, which is difficult to verify independently, with limited transparency into the financial impact of cost overruns, and the inclusion of "soft costs" such as construction, financing, insurance, or fees.

⁴² *Id*.

⁴³ "Distance from a shore/port suitable for installation and water depth both impact total installed costs, given the return trips to port for foundations and turbines during installation, and size of the foundations. The distance to port also has an impact on O&M costs and decommissioning costs. In European waters, the trend to site wind farms farther from shore has also been correlated with harsher weather conditions making installation more difficult, this has added time and cost to the already high logistical costs when projects are farther from ports (EEA, 2009)." See IRENA 2019 Costs, p. 76.

Q56. What do you conclude with regard to your review of the study prepared for
 NYSERDA?

A56. The Renewables Consulting Group ("RCG") prepared an analysis for NYSERDA "to
assess the deployment, cost and benefit of incremental renewable energy resource under
Tier 1 of the Renewable Energy Standard (RES) and the Offshore Wind Standard"⁴⁴ in
New York. Based on a review of that whitepaper, there are several important points to
highlight.

8 First, items that we included in our offshore wind capital cost estimate such as working 9 capital, owner's development costs, and financing fees, are not included in the NYSERDA 10 values. These costs represented approximately 10% of the total installed cost for the 11 offshore wind facility that was the subject of the Mott MacDonald capital cost analysis.

More generally, the actual basis for the capital cost estimates in the NYSERDA study is opaque and not available on the record at all; the whitepaper notes that the "Base Case' offshore wind capital cost assumptions are based on a proprietary model developed by RCG that contains cost data and forward-looking cost assessments through 2040."⁴⁵ Thus, there is no basis upon which an expert can ascertain whether their estimate was produced consistent with a proper scope of work for an offshore wind project to be developed in the

⁴⁴ NYSERDA White Paper, Appendix A – Cost Analysis, p. 3.

⁴⁵ *Id.*, p. 28.

1 offshore wind lease areas off the New England or New York coastline.

2 Moreover, on the basis of Mott MacDonald's detailed bottom-up estimates, I have 3 concluded that the cost estimate in the NYSERDA study is far too low to be reasonable – 4 or even plausible.

5 Consistent with the other studies reviewed, these studies do not explain their primary data 6 sources. These may not be complete, may have omitted costs, or may simply be high-level 7 estimates. Without provenance for their cost data, there is no basis to evaluate their 8 reasonableness or accuracy. As a result, the opacity and unstated basis for their estimates 9 means their validity cannot be reasonably evaluated, and as a consequence, I did not 10 consider these sources in our benchmarking exercise.

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Q57. What do you conclude with regard to the IRENA studies?

12 A57. We reviewed the two most recent studies published by IRENA, which analyzes global costs and trends for renewable technologies. As noted in the table above, the studies published 13 14 by IRENA rely on European and other global projects on which to base their estimates. As I explained above, for a true comparison between a U.S. offshore wind project and a 15 16 European offshore wind project, the scopes of work should be comparable. However, 17 IRENA notes that the scope of work on which these values are based vary widely from 18 country to country. Thus, the IRENA data is not a reliable source for benchmarking the 19 costs of a large-scale offshore wind project in New England, as it is not possible to verify 20 that the scopes of work for the projects IRENA reviewed are reasonably comparable to the 21 scope of work that would be required for a New England project, or to ensure that the

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IRENA study appropriately accounted for differences in the scopes of work.

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Q58. What do you conclude with regard to the EPA 2018 IPM Platform?

3 A58. EPA's documentation for its Integrated Planning Model Power Sector Modeling Platform 4 2018 Reference Case provides a base value as well as suggested adders to reflect regional 5 cost differences and impacts from short-term risks. During stakeholder discussions of the offshore wind ORTP, proponents of this study cited the unadjusted "base" capital cost 6 7 estimate, and did not appropriately consider regional cost differences and impacts from 8 short-term risks. While the base value reported as adjusted for these adders (\$6,705/kW) is 9 comparable to that derived by Mott MacDonald, the underlying data in the study is based on the 2016 NREL Annual Technology Baseline⁴⁶; therefore, the values reflected in the 10 11 2020 NREL Annual Technology Baseline are deemed more appropriate for benchmarking 12 purposes.

13 Q59. What do you conclude with regard to the 2019 Lazard Report?

A59. The source of the data reported in the Lazard: 2019 Levelized Cost of Energy report was not transparent, with statements throughout the report noting that the data was based on "Lazard estimates."⁴⁷ Further, the report acknowledges that the estimate does not encompass the full scope of the development costs, including "network upgrades, transmission, congestion or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various

⁴⁶ "For offshore wind, the parameters shown are based on the NREL's 2016 ATB mid-case." *See* p. 4-30 at https://www.epa.gov/airmarkets/documentation-ipm-platform-v6-november-2018-reference-case-all-chapters

⁴⁷ See https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf

environmental regulations (e.g., carbon emissions offsets or emissions control systems)."⁴⁸
 Therefore, it is not reasonable to use the resulting estimate as a basis for benchmarking an
 "all-in" capital cost estimate, as is expected for us in the development of the ORTPs.

4 Q60. What do you conclude with regard to the Dominion Integrated Resource Plan?

5 The Dominion Integrated Resource Plan value referenced in proponents' proposals is A60. opaque at best. The plan provides a Levelized Cost of Energy for Offshore wind, and notes 6 7 that is was derived by "a busbar (i.e., LCOE) screening model".⁴⁹ However, there is no 8 detail regarding the methodology or assumptions used in the model. CEA has not been 9 able to identify the source for the data, the assumed distance to shore, whether the estimates include interconnection costs, etc., and therefore is unable to evaluate or confirm the 10 11 comparability of the estimate for use in benchmarking a capital cost estimate for a New 12 England project.

Q61. What are your conclusions based on your review of these publicly available benchmarking studies?

15 A61. We reviewed an extensive list of external studies and published estimates of the capital 16 costs of new offshore wind projects. We found that these studies differ in their estimated 17 values, as can be expected for a newly developing technology that is being installed in 18 divergent regions of the world. The most important and striking dimension is that the 19 offshore wind capital costs estimated values differ systematically between New England-

⁴⁸ See <u>https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf</u> at p. 1.

⁴⁹ Virginia Electric and Power Company's Report of Its Integrated Resource Plan, Virginia State Corporation Commission Docket No. PUR-2020-00035, Virginia Electric and Power Company 2020 IRP, Appendix 5N – Busbar Assumptions, document page 245; available at <u>https://www.dominionenergy.com//media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509</u>.

1 focused, bottom-up engineering-cost estimates performed by reputable firms with 2 significant offshore wind development experience, and those from general surveys without 3 the benefit of that expertise. The New England-focused estimates provide useful 4 benchmarks, and – most importantly – all fall in a similar range to the bottom-up 5 engineering-based capital cost estimate for offshore wind in New England developed 6 independently by Mott MacDonald.

Conversely, the other estimates are lower, but those studies have not been adjusted for regional factors, including differences in project scopes. In addition, in the case of the IRENA data, it is not possible to discern whether or how regional differences were accounted for. As I have explained, however, regional differences and differences in project scope can have significant impacts on the expected cost of an offshore wind project. As a result, studies that do not clearly account for these differences are not comparable or informative to the determination of the ORTP value for the New England markets.

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Q62. Is this benchmarking exercise valuable?

15 A62. Yes, the benchmarking exercise is valuable because the most applicable external reports 16 provide useful corroborating information that support the value obtained by Mott 17 MacDonald as reasonable for the capital costs of a new offshore wind project in New 18 England.

19 Q63. Does this conclude your direct testimony?

20 A63. Yes.
VERIFICATION

I, Danielle S. Powers, Senior Vice President, affirm under penalty of perjury, that the foregoing representations are true to the best of my knowledge, information, and belief.

Dated April 6, 2021.

Januelle S. Powers



DANIELLE S. POWERS

Senior Vice President

Ms. Powers has over 30 years of experience in the energy industry. She has specific energy market expertise in the areas of wholesale market design and operations, power generation, and transmission system planning and operations. Ms. Powers has been extensively involved in the design, implementation, and operation of installed capacity markets across North America. She has experience in executing both regulated and unregulated fossil and renewable generation asset sale transactions in the areas of regulatory analysis, policy development, due diligence analyses, energy market assessment, and business unit strategy. Ms. Powers has also prepared market assessments and forecasts and has advised several clients on the procurement of competitive electricity.

REPRESENTATIVE PROJECT EXPERIENCE

Wholesale Market Assessment and Design

Ms. Powers has worked with ISO-NE for the past 14 years supporting analysis on wholesale energy and capacity market implementation and operation. This work has involved analyzing the cost of installing and operating a variety of candidate technologies for new entry into the market, production cost modeling to calculate the expected energy and ancillary service revenues that would be earned by the technology, and financial analysis to calculate the appropriate capital structure for the new technology. These technologies included gas-fired generation, wind and solar resources, demand response and energy efficiency resources, and energy storage resources. As part of her responsibility for the design and approval of the New England Forward Capacity Market for ISO-NE, Ms. Powers was responsible for managing the market design effort, designing the processes and procedures around resource qualification, resource bids and offers, auction clearing determination of installed capacity requirements and market settlement. She was responsible for all stakeholder interactions and meeting facilitation involving approximately 20 meetings over a six-month period. This involved forming several external project teams made up of New England participants to gather input on major market design elements to ensure that the final design reflected the involvement of affected parties and addressed their business concerns.

Resource Planning

Ms. Powers has provided a broad spectrum of resource planning services to electric and combination utilities throughout North America. Ms. Powers has provided third-party assessments of resource plans and procurement decisions and has managed competitive solicitations for power on behalf of several clients. Ms. Powers has supported clients in the development of integrated resource plans and certificates of public need and necessity.

Expert Testimony and Litigation Support

Ms. Powers provides expert testimony in regulatory proceedings on energy and capacity market design and operational issues. In addition to developing and sponsoring expert testimony, specific services provided include collaborating with counsel as well as business and technical staff to



clients to develop litigation strategies; preparing and reviewing discovery and briefing materials; and preparing materials and participating in sessions with regulators and interveners.

Transmission Planning and Interconnections

Ms. Powers has worked with several clients in evaluating transmission alternatives, both regulated and competitive. This work has involved evaluating transmission tariffs, evaluating and managing interconnection processes, preparing and negotiating interconnection contracts, and performing project cost reconciliations. Ms. Powers has provided consultation on required Federal Energy Regulatory Commission (FERC) filings and is responsible for staying abreast of relevant regulatory issues to ensure compliance with regional and FERC requirements.

Asset Sales

Ms. Powers has managed and been involved in the sale of over 12,000 MW of generation resources, purchased power contract, and transmission assets. This work included involvement in the areas of marketing, labor, environmental, transmission, market analysis, regulatory, terms of sale, legal, transition power sales, and bid evaluation. Acted as client representative for bidder groups providing technical expertise and assistance. Provided full support for the initial and final due diligence processes.

Retail Energy Planning and Business Development

Ms. Powers has been involved in securing electricity supply for various buying groups and end users. She has developed strategic energy plans to enable the competitive energy procurement and energy usage analysis. This work has included the development and implementation of business plans to evaluate the opportunities and risks associated with alternative supply of energy.

Power Plant Operations and Engineering

In her role as a production engineer, Ms. Powers managed several large-scale projects involving environmental controls and operational optimization. This work involved having overall responsibility for the operation, maintenance, and overall performance of station pollution control systems. She has managed all facets of various plant construction projects including project engineering, construction supervision, project estimating and scheduling, and budget tracking/analysis.



PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2005 – Present)

Senior Vice President Vice President Assistant Vice President

ISO New England (2003 – 2005) Principal Analyst

Concentric Energy Advisors, Inc. (2003) Executive Advisor

Navigant Consulting, Inc. (1999 – 2003) Senior Engagement Manager

XENERGY, Inc. (1997 – 1999) Manager of Strategic Energy Planning

New England Power Company (1989 – 1997) Intern, Production Engineer

EDUCATION

Bentley College M.B.A., *magna cum laude*, 2000

University of Massachusetts, Amherst B.S., Mechanical Engineering, 1988

PROFESSIONAL AFFILIATIONS

Board Member – Atlantic Power Corporation EIT Certification (Engineer-in-Training) Member of the Massachusetts Restructuring Roundtable Total Quality Management - Certified Team Facilitator



SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT		
Federal Energy Regulatory Commission						
ISO New England	8/2009	ISO New England	Docket No. ER09- 1424-000	Resource Planning, Market Design & Rules, Power contract structure & negotiation		
ISO New England	1/2017	ISO New England	Docket No. ER17- 795-000	Wholesale Market Design		
ISO New England	12/2020	ISO New England	Docket No. ER21- 000	Wholesale Market Design		
Connecticut Siting	Council	•	•	•		
Competitive Power Ventures	11/2014	Competitive Power Ventures	CT Siting Council 192b	Expert Report regarding Certificate of Environmental Compatibility and Public Need		
Massachusetts Dist	rictCourt	•	•			
GDF SUEZ Energy North America	10/2014	Donna West vs. FirstLight Power Resources Services, LLC, et al.	Donna Westvs. FirstLight Power Resources Services, LLC, et al.	Resource Planning, Market Design & Rules		
Illinois Commerce	Commission	1				
Ameren Illinois Company	5/2019	Ameren Illinois Company	Docket No. 18- 1617	Acquisition of a transmission line and generating asset		
Indiana Utility Regulatory Commission						
Indianapolis Power & Light Company	2/2021	Indianapolis Power & Light Company	Cause No. 45493	Resource Planning		

Attachment I-1f

Mott MacDonald, Inc. Offshore Wind Report



Mott MacDonald Offshore Wind ORTP Report

ISO-NE ORTP Analysis

April 6, 2021

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ISO New England

Mott MacDonald Offshore Wind ORTP Report

ISO-NE ORTP Analysis

April 6, 2021

Information class: Standard

This document is issued for the party which commissioned it and for specific purposes connected with the abovecaptioned project only.

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1 Introduction

1.1 Purpose of Report

Mott MacDonald is providing this report in support of the ISO New England Inc. (ISO-NE) Offer Review Trigger Price (ORTP) Analysis that was conducted in late 2019 through 2020 for the offshore wind technology. As part of this analysis and in accordance with the ISO-NE Tariff, a "bottom-up", engineering-based cost estimate was developed by Mott MacDonald. This report describes the development and value of the bottom-up estimate, and associated project scope assumptions, for a reference offshore wind project for the ISO-NE ORTP Analysis utilizing Mott MacDonald's global industry sector experience and confidential industry databases. 1

1.2 Report Authors

Keith Paul

Keith Paul is a Senior Consultant in Mott MacDonald's Consulting Engineering Practice. He has over 25 years of experience in the power industry and holds an MBA from Babson College. Mr. Paul provides insights to many of his clients in the ever-changing power industry landscape.

He was responsible for the ISO-NE's Cost of New Entry (CONE) analysis of 2016 and he has been the principal energy consultant for this CONE analysis of 2019.

He has conducted numerous evaluations and analyses of performance of many thermal and renewable projects throughout his career. He has provided consulting services to onshore and offshore wind project managers within Mott MacDonald on an as-needed basis.

Mr. Paul was the lead engineer on, and oversaw all the work on, the development of the offshore wind capital cost analysis that is explained in this report. He is also the lead author of, and oversaw all aspects of the preparation of, this report.

Hassan Hamdan

Hassan Hamdan is Head of the Techno-Economic Practice in the US. He has over 20 years' experience in the power industry and holds an MBA from Boston University. He has been involved in various technologies covering technology evaluations and cost estimates. He has performed techno-economic analyses for many of the Mott MacDonald clients involved in the Offshore Wind parks planned for the East Coast of the US.

Joseph Farrell

Joseph Farrell has been a power engineer for 4 years in Mott MacDonald's engineering division. Mr. Farrell has been involved in many thermal and renewable projects supporting Keith Paul and is very familiar with the challenges in the power industry. He has been a vital part of the Mott MacDonald team for this 2019 CONE analysis from the project start.

Alberto Ferrer

Al Ferrer has been involved in the power industry for over 35 years in the US and overseas. He is the leader of Mott MacDonald's Energy Consulting practice in the US. He has conducted many evaluations of major and minor projects involving the large majority of commercially available technology and in research and development in the power industry. He has been involved in complex projects involving nuclear power, geothermal, CSP, PV, onshore and offshore wind. He has supervised the technical, schedule and cost evaluations of many of these projects, becoming a valuable resource to the client base. He has overseen the work and

analyses conducted by Keith Paul and Joe Farrell for ISO-NE for the past two years. He is an expert in the execution of various types of power generation projects, both thermal and renewables in the US.

2 Overall Approach – Summary

Mott MacDonald is a Global Engineering and Technical Consultant leader providing engineering consulting, design and technical support services all over the world. To date, Mott MacDonald has provided engineering and technical services to over 90 GW of offshore wind energy projects worldwide. In North America, we have an offshore wind staff of more than 20 personnel, supported by over 3,000 engineers across the United States and an international staff pool including around 250 staff dedicated to offshore wind.

Utilizing this talent and experience, we have compiled a confidential database of offshore wind components, a detailed understanding of offshore wind project scope and engineering requirements, and offshore wind total installed costs. We have employed data for this engagement and others to develop, compare, and estimate offshore wind project costs all over the world. For this New England engagement, we first performed a thorough assessment of the project scope for a reference offshore wind project in New England, as discussed in more detail below. We employed our detailed project component cost data to perform a bottom-up, engineering-cost-based estimate of the total capital costs for the reference offshore wind project in New England. That total capital cost estimate was then used by Concentric Energy Advisors to structure a financial model used to calculate the ORTP value for the offshore wind technology, as described in the Direct Testimony of Danielle S. Powers of Concentric Energy Advisors, which was also prepared in support of ISO-NE's filing.

The first part of developing a cost estimate for an offshore wind project in New England includes identifying the technical scope of work and the contractual and management approaches to be used for the project. The scope of work identifies the technical equipment required by the project. This scope of work matched the needs of the project, from the size (power generation capacity) of the project, to weather conditions, to system interconnection requirements, to water depth, to turbine spacing requirements, to lease location and interconnection locations, the equipment redundancy required for reliability, and several additional factors as detailed in our report. The turbine type selected for the project, along with the power required at the Point of Interconnection (POI), sets the equipment scope in more detail.

Once the technical scope was established, the cost estimating effort was undertaken. Mott MacDonald, as stated above, primarily utilizes an internally developed confidential database to develop costs. These costs are adjusted as necessary to New England region-specific conditions. This can include scope adjustments and labor and construction cost adjustments as appropriate. The final cost estimate was established for an offshore wind project located in federal waters known as the Massachusetts Offshore Wind Energy Area (referred to herein as the "Massachusetts lease area"), delivering up to 800 MW to the point of interconnection (POI) with the New England high-voltage transmission system located at Brayton Point, Massachusetts. In response to ISO-NE's direct request, where possible Mott MacDonald used the lower-cost option estimate (for example, when choosing the method for laying the cabling that connects the offshore wind farm to the onshore POI), so that the capital cost estimate is at the lower-end of the competitive cost range.

3 Mott MacDonald's Experience Developing Offshore Wind Projects

3.1 Mott MacDonald's Global Offshore Wind Experience

Mott MacDonald has been involved in offshore wind power projects for over 15 years and has pioneered technical advisory in this field from the first offshore wind farm that was project financed. To date, we have provided engineering and technical advisory services for over 90 GW of wind energy with high volumes of work in Japan, Taiwan, USA, and Europe. In the last five years (2015 – 2019) and the first half of 2020, we supported over sixteen (16) offshore wind projects, with a total value of over USD 15 Billion.

Mott MacDonald's experience and services to the offshore wind industry include:

- Project development assistance and Owner's Engineer (OE) assignments
- Due diligence studies and full Lender's Technical Advisor (LTA) assignments
- Technology assessments
- Pre and Feasibility studies
- Energy yield analysis / performance assessments
- Conceptual design and optimization
- Undersea interconnection and offshore substation studies
- Grid analysis and system studies
- Specification and tender adjudication
- Contractual reviews and contract negotiations
- Construction and operations monitoring
- Technical strategic advice
- Environmental and Social Impact Assessment (ESIA)
- Investment and acquisition appraisal

Our multidisciplinary engineering teams include specialists with experience in all renewable technologies, yield analysis, project feasibility and development, grid connection and power transmission, cost estimating and schedule developments, environmental and social impact assessment, policy and regulation, operations and maintenance support and commercial evaluations.

3.2 Mott MacDonald's U.S. Offshore Wind Experience

Mott MacDonald has provided engineering and technical advisory services for over 9 GW of wind energy in the United States, including acting as Owner's Engineer for the first offshore wind project in the US (the Block Island offshore wind facility, in Rhode Island) and supporting 15+ other US offshore wind projects in various stages of development. This support includes Owner's Engineering and Engineering and Design roles.

The Owner's Engineer identifies the project location, determines the equipment required to achieve project objectives, and drafts technical documents used in the competitive bid process for a fixed price engineering, procurement, and construction contract. The scope of the Owner's Engineer work includes pre-feasibility studies for project development and strategy evaluation to

determine what is technically required for a potential offshore wind project in a particular area. Technical support is provided for the acquisition of the lease area and aspects of a power purchase agreement. Project management and development support is provided for all technical aspects of the project, including review of proposed arrangements and designs, and all accompanying technical engineering and design packages. Construction management services are provided onshore at the project staging area and offshore when the project reaches that stage of development.

Engineering and Design services include detailed engineering of the offshore foundations and structural supports for the wind turbines and the offshore electrical substation platform. Engineering for the offshore cables and their routings may be provided. The services could also include performing technical surveys of the seabed in the area of the wind turbines and the cable routings. The preferred landfall methodology is evaluated and selected along with onshore cable routing. Environmental engineering services and permitting services are provided to the owner to obtain all permits and licenses as required.

Mott MacDonald provides the following two examples of our experience on offshore wind projects in the US in various stages of development:

Project 1: Mott MacDonald developed the engineering concept for an 800MW offshore wind project, providing analysis of options for the electrical balance of the plant equipment. This technical effort evaluated the output from the wind turbines sent through the inter-array cables to the substation platform. Two different options for connecting the substation platform to the point of interconnection were also evaluated. The system studies included optimization of the configuration of the export system, factoring in the service voltage level, the length of the circuits, the possible arrangements of the reactive power compensation plant and the operability of the electrical system.

Project 2: Mott MacDonald was the Owner's Engineer for the offshore element of a 25MW US offshore wind project comprising six 4MW wind turbines, which connected to the onshore transmission network at 69kV. Scope of work for wind turbine engineering included electrical transmission studies, extreme wind energy analysis, basis of designs for site specific electrical load analysis, procurement turbine technology reviews, turbine port staging development, transportation and installation development, design of foundation and turbine electrical system, turbine scoping documents and wind turbine long term services agreement contract negotiation support. Mott MacDonald was also responsible for the electrical package that consisted of cable and substation scoping documents, electrical tender analysis, analysis and resolution of grid dynamic model utilizing PSS/E, undertaking FEED design (single line diagrams) for entire electrical network including Terminal Points on wind turbine units, US electrical code definitions, electrical loss and reactive power calculations.

These are just two examples of many that Mott MacDonald has performed for offshore wind projects along the East Coast of the United States and around the world. This experience provides us with the knowledge and understanding of the technologies employed and the technical requirements of these offshore wind projects. In addition, local knowledge provides us with a detailed understanding that, coupled with our extensive experience, assists in the development of projects that achieve their design goals in a cost effective way.

3.3 Mott MacDonald's New England Offshore Wind Experience

In addition to the previously mentioned US roles described in Section 3.2, Mott MacDonald has direct experience with offshore wind projects in New England. Two additional assessments and scopes of work that were conducted specifically in the New England region are:

Project 3: This scope of work included the completion of system studies, including evaluation of the compliance with the interconnection conditions per ISO-NE requirements, a comparison analysis of this project scope to other projects, and refinement of the design of the electrical balance of plant for the project's electrical system. Project efforts included support for the development of the design of the electrical balance of plant through formulation of operating scenarios, the onshore portion of the project's substation general arrangements, and the technical specifications for the main electrical equipment. Mott MacDonald also prepared technical documentation for the grid connection application with an improved design of the electrical system, including change of concept and change of the wind turbine generator (WTG) unit.

Project 4: Mott MacDonald provided a range of Owner's Engineering services including feasibility studies, conceptual design, cost estimates, permitting, and public relations for an offshore wind facility. These services optimize the layout of the site to maximize production and minimize electrical losses, determine optimal equipment sizing and location, and minimize costs. Additionally, Mott MacDonald determined the scope of supply and scope of work required to fully develop and construct the facility. In this case, we provided overhead and underground distribution design, interconnection support, and support during technical discussions between the client and various vendors and utilities. Mott MacDonald provided assistance with the utility interconnection procedures, development of engineering, procurement and construction (EPC) contract documents and oversight of the EPC contractor. Mott MacDonald continues to provide support to this facility; our current role is conducting operations monitoring to oversee and periodically audit the Operations and Maintenance activities of the facility, including overseeing long-term performance of the facility.

Mott MacDonald's extensive experience with offshore wind development provides a sound engineering background for new offshore wind projects in New England. Mott MacDonald leverages technical knowledge with local familiarity to provide technical insight, data, and expertise on the necessary scope of work to successfully develop offshore wind projects in the New England region, the US, and throughout the world.

This combination of technical knowledge and local familiarity allows for the development of reliable estimates of the capital costs for offshore wind projects in the New England region, based on bottom-up engineering cost estimates that match the scope of the work involved. Our global experience with offshore wind projects in the 800 MW size range, located in varying geological and sea conditions and interconnecting at various distances, allows us to develop and reliably estimate the costs of similar-size offshore wind projects. Our local familiarity with the New England grid further assists in leveraging local knowledge with the international knowledge our staff brings to these projects. This combination of experiences further optimizes designs and technical scopes, and results in costs structured during the project development stage that are representative of final costs.

4 Project Scope and Significant Factors Determining the Capital Costs for the Representative Offshore Wind Facility

4.1 Mott MacDonald Offshore Wind Cost Component Data

Mott MacDonald developed the major equipment costs, field construction labor hours, and other quantities used to develop the bottom-up cost estimate from the comprehensive Mott MacDonald offshore wind cost estimation database. Knowledge gained from prior offshore wind project engagements globally, customized for the size, location, and configuration selected for this New England reference offshore wind project, further informed our cost estimate.

Mott MacDonald maintains a confidential database of project costs for power generation technologies all over the world. The database was developed from data provided to, and produced by, Mott MacDonald for actual projects and transactions (generally under nondisclosure agreements). The database includes data from multiple large offshore wind projects with different locations, ambient conditions, geological formations, distances from shore, depth of water, different labor and construction practices, and various scopes of installation. This database provides Mott MacDonald with costing information for all components required for offshore wind project development, including cost estimation for the reference offshore wind project in New England in this study.

The specific data sources used for the reference offshore wind project in New England consist of actual project cost (and component cost) estimates for several offshore wind projects in development, in construction, and currently operating around the world over the last decade. The northern European offshore wind market has been the most active recently, and several reference projects are from the North Sea region. Once similar projects and equipment were identified, we made adjustments to the data for specific application to the ISO-NE Massachusetts 800 MW reference offshore wind project.

4.2 Bottom-up Engineering-Based Cost Estimates: Overview

The core components of the bottom-up analysis detailed the specific project requirements and then developed a reasonable scope of work which informed the overall cost estimate.

For the New England offshore wind ORTP study, the reference scenario consists of a new, reference offshore wind facility that is assumed to be located in the Massachusetts Offshore Wind Energy Area¹ located off the southeast coast of New England, as described further below.

A scope of work needs to be well-defined to outline the project from inception to commissioning. Thus, the estimate involves all major components, costs, contingencies, uncertainties, etc. that will be necessary to deliver 800 MW to the POI at Brayton Point, Massachusetts, as discussed below. Some categories that were considered include, but were not limited to:

• Project development costs associated with the location such as the wind resource evaluation, environmental assessments, permitting costs, etc.;

¹ An overview of the activities underway in the Massachusetts lease area is provided by the Bureau of Ocean Energy Management at https://www.boem.gov/renewable-energy/state-activities/massachusetts-activities.

- Project EPC capital cost estimate for construction, based on modern regional construction techniques, field construction labor hours, and materials for electricity generating equipment and related facilities;
- Interconnection costs and required onshore electrical system costs, as needed to design, construct, and interconnect the facility's electrical output to the existing New England highvoltage transmission system;
- Site acquisition costs, which include acquiring the offshore lease area and the onshore area for electrical landfall;
- Permitting costs required to construct and operate an offshore wind facility in New England;
- Potential environmental abatement costs that may arise during development, construction, or operation, if any; and
- Project contingencies associated with the firmness and risks associated with the input information.

This approach provided an independent estimate based on a reasonable scope of work and assumptions, using cost component estimates from our database adjusted to address specific local requirements and regulations.

4.3 Scope of Work – Initial Stage

The development of an offshore wind estimate first requires development of the representative project details that provide the technical basis for the project. First, a definition of the size and location of the project must be developed. In the case of ISO-NE, the project size was based on the size of offshore wind projects being proposed presently (2019-2020) and in the near future. The project size modeled is 800 MW of installed capacity at the point of electrical interconnection.

The location for this project was intended to represent expected locations, generally, for new offshore wind projects that will connect to the high-voltage transmission system operated by ISO-NE. Offshore wind projects being proposed in New England today and in the near-term future have been located in the Massachusetts or Rhode Island offshore lease areas. The majority of projects have been in the Massachusetts offshore region. As a result, a Massachusetts lease area was selected. The following hybrid map shows the Massachusetts offshore lease area, which has an average water depth of approximately 150 feet.² The ISO-NE transmission grid map is also shown.

As a legend to the map below, the 345kV transmission system is represented by the dark blue lines running throughout the land areas of lower New England that are shown on the map. The assumed POI of Brayton Point is highlighted with a bright pink circle, which can be found near the Massachusetts and Rhode Island border. The Massachusetts Offshore Wind Energy Area is depicted by adjacent offshore areas of different colors directly south of Martha's Vineyard. The lease areas are currently owned by:

- Blue and Brown Deepwater Wind
- Orange Bay State Wind
- Off-white and Green Vineyard Wind
- Pink Equinor Wind US
- Purple Mayflower Wind Energy

² Note that the displayed water depths on the NOAA Ocean Depth map are in fathoms.

Figure 4.1: Massachusetts Offshore Wind Lease Areas



Sources: NOAA ocean depth map. ISO-NE Transmission map.

The location of the Massachusetts lease areas, and their proximity to Block Island, Rhode Island and Martha's Vineyard Massachusetts, means developed projects will be located further out to sea from the main New England coastline so that the offshore wind turbines would not be visible from land. The distance out to sea significantly increases the cost of the large high-voltage cabling and the associated undersea costs. Undersea cable needs to be protected from ships, fishing, storms, marine life, etc., and therefore must be buried or shielded and not just laid on the ocean bottom. The distance this cable must travel significantly impacts costs. The longer the distance, the higher the project costs. The total offshore distance (as the cables are routed, as discussed below) for the ISO-NE offshore wind reference project is 60 miles. Deeper water depths also increase cost, especially for the offshore substation platform.

Finally, the POI was chosen based on access to the ISO-NE 345 kV transmission network. Three focal 345kV POIs have been used for new offshore wind projects in New England to date: Barnstable, MA, Brayton Point in Somerset, MA, and Kent County, RI. The Barnstable location has already been selected by a project in development that takes up 100% of its capacity, so Barnstable was eliminated for this reference offshore wind project's POI. The Brayton Point and Kent County locations are both available. The Brayton Point location was selected as the reference project POI. Other locations discussed were much further away from the project site or require cable crossings that would drive up costs considerably. As noted previously, the Brayton Point POI is approximately 60 miles from the selected Massachusetts lease area.

Other costs associated with the transition box at Brayton Point, where the undersea cables transition to onshore cables, are included but will not differ much from standard cost assumptions for offshore wind projects that incorporate similar facilities. This is due to the relatively short distance from the transition box to the existing Brayton Point electrical substation. Electrical upgrades to the substation at Brayton Point are considered minimal as the existing substation was designed for approximately 1,500 MW of fossil generation that has been retired and decommissioned (demolished).

In summary, the 800 MW ISO-NE ORTP reference offshore wind project is located in the Massachusetts lease area in federal waters and is interconnected to the 345 kV system at Brayton Point. While utilizing the Massachusetts lease areas and Brayton Point as the POI are reasonable options for this representative offshore wind project, it is important to note the 60-mile marine transmission distance offshore to reach these lease areas is a long run, and has a significant impact on the total project costs.

4.4 Scope of Work – Scoping Stage

Once the basic project size and location are determined, decisions on project equipment and design are needed to achieve the desired project capabilities. Figure 4.2 depicts the scope of work that was reasonably determined for the reference 800 MW offshore wind project off the coast of Massachusetts. This figure summarizes the main components for which costs were estimated, including:

- Wind Turbines
- Inter-array Cabling
- Offshore Collector Substation
- Submarine Export Cabling
- Landfall and the Transition to Onshore
- Onshore Facilities and Electrical Interconnection

Additionally, project contingency costs and owner's development costs were included, as well as costs related to financing and working capital. The cost development process for each of these major components are described in further detail below.



Figure 4.2: Typical Offshore Wind Scope of Work

Source: Mott MacDonald

Capital costs for offshore wind facilities vary significantly from project to project due to sitespecific conditions, regulatory requirements, and development and installation costs. In calculating an appropriate capital cost for the reference wind facility, Mott MacDonald applied our global and local experience in addition to using our confidential database on offshore wind projects, which is regularly updated to accurately represent offshore wind facility capital costs. The assumed all-in "overnight" capital costs for the reference offshore wind facility are summarized in the table below, and described in relation to the assumed scope of work above.

Table 4.1: Mott MacDonald Reference Offshore Wind Project Overnight Capital Cost Breakdown

Cost Component	2019\$*	2019\$/kW (Nameplate)
Turbines and Major Equipment	\$2,333,000,000	
Inter-array Cabling	\$242,250,000	
Offshore Substation Platform	\$465,000,000	
Submarine Export Cabling	\$583,000,000	
Landfall Transition Box	\$40,000,000	
Project Contingency	\$183,163,000	
TOTAL EPC COSTS	\$3,846,413,000	\$4,808
Owner's Development Costs	\$192,320,000	
Electrical Interconnection & Upgrades	\$55,000,000	
Financing Fees	\$153,857,000	
Working Capital	\$38,464,000	
TOTAL NON-EPC COSTS	\$439,641,000	\$550
TOTAL OVERNIGHT CAPITAL COSTS	\$4,286,054,000	\$5,358

*Numbers may reflect rounding

4.4.1 Turbines and Major Equipment

A main component of any wind power facility are the wind turbine generators. The wind turbine generators offered by the industry's main manufacturers are continuing to increase in size and

efficiency, affecting all other wind plant and delivery costs. While global offshore wind projects as of early 2020 were using 10 MW wind turbines, it was anticipated that the newer 12 MW machines from GE, Siemens, or MHI/Vestas would be more appropriate for the ORTP reference offshore wind project design, which is modeled to begin construction in 2023. The reference offshore wind project is assumed to procure 67 wind turbine generators (WTG), at 12 MW each, to achieve the plant capacity of 800 MW net capacity at the point of injection on the grid side.

The turbines were priced using standard quotes from wind turbine generator manufacturers. The scope provided by the manufacturers includes, but is not limited to, the blades, the tower, gearbox, generator, and step-up transformer that will increase the voltage to 66kV prior to the inter-array cabling (described in the next section). The overall major equipment costs also include the shipping, installation, and construction associated with the offshore wind turbines. The assumed foundation for all 67 wind turbines is a concrete monopile, which is typical for a water depth of 130 to 170 feet based on Mott MacDonald's experience. A monopile is a single-cylindrical foundation that is forced into the seabed to support the offshore wind turbine.

The wind turbines and major equipment for the modeled facility have an estimated cost of approximately \$2.3 billion. This is based on the specific scope provided above and the component data costs from the Mott MacDonald confidential database.

4.4.2 Inter-array Cabling

Inter-array cabling is the electrical cabling that interconnects approximately five or six WTG in series. This is an XLPE three (3) core copper cable with a voltage level of 66kV and a cross section of 300 mm²; typical characteristics for an offshore wind inter-array cable that is installed on top of the seabed. A one-mile radius between each turbine is assumed between wind turbines to reduce wake losses and the risk of interference with other turbines, and to increase safety for fishing and shipping vessels.

Once the fifth or sixth turbine is connected, the cabling size increases (due to the increased load from five to six turbines) to 600 mm² to ultimately connect the string of turbines to the offshore collector substation. For this project, Mott MacDonald assumed twelve 3-core copper 66kV, 600 mm² cables will be installed, which is the total number of cables connecting the entire wind farm to the collector platform.

The total assumed quantity of inter-array cabling was equivalent to 85 miles. This number was calculated by the 1-mile separation between turbines while adding additional 600 mm² cabling to connect each 5 to 6 wind turbine groupings to the offshore collector substation. Using an average per-mile cost that includes the installation of the cables to be laid on the seabed, the 66 kV cabling resulted in an estimated cost of \$242 million (in 2019 dollars).

It is important to note that the increased turbine MW size decreases the wind turbine quantity to reach the agreed upon 800 MW net capacity at the injection point. However, the inter-array cabling between turbines will be relatively similar; there are fewer turbines to interconnect but the distances between the turbines increase as the wind turbine rotor diameters increase, and each cable transmits more power from each turbine.

The inter-array cabling estimated cost of \$242 million is based on the specific scope provided above and the reference data within the Mott MacDonald proprietary database.

4.4.3 Offshore Collector Substation

The twelve (12) estimated 600 mm² inter-array cables will travel along the seabed from the offshore wind turbines, travel to the water surface where they will be collected using to-be-

constructed design components known as "J-tubes," and then connect to an approximately 3,000 ton topside offshore collector substation. This offshore substation is assumed to be a 4-legged jacket permanent structure constructed roughly at 80 feet above sea level. The offshore collector substation collects and stabilizes the power generated by the wind turbines to prepare it for transmission to shore. The substation reduces the potential electrical losses that would occur if a WTG located offshore were to send the electricity directly to shore, by increasing the voltage of the power generated offshore.

The inter-array cabling will enter the offshore collector substation and connect to gas-insulated switchgear (GIS), followed by two (2) 450 MVA transformers to increase the voltage from 66kV to 275kV, and two (2) large shunt reactors to manage cable voltage and charging current. This assists in stabilizing the voltage and reduces system losses to transmit the power to shore. This offshore collector substation will also have all the necessary additions that are typical for a substation of this size, including auxiliary power requirements, service station transformer, platform ambient management system, backup generator, protection and control system, and circuit breakers for each 66kV cable.

The offshore collector substation estimated equipment procurement and construction costs of \$465 million is based on the scope summarized above, as well as our experience with substation projects for power generation and customization of the data used within the Mott MacDonald confidential database for the Massachusetts offshore lease areas.

4.4.4 Submarine Export Cabling

Submarine export cabling sends the power collected at the offshore collector substation to the onshore interconnection point. This cabling is typically larger than the inter-array cabling, 1,800 mm² or sometimes larger (as compared to the 300mm² and 600mm² for inter-array cables). This increase in cable size is due to the larger capacity being transmitted and also for the longer distance traveled by the submarine export cabling. Note that if cables and transformers were smaller, for example, they would cost slightly less, but electrical losses would increase, meaning the project would not achieve 800 MW at the POI without increasing generation capacity, which would significantly increase costs.

This cabling is assumed to be alternating current (AC). AC-cabling is more appropriate for the distance and capacity of this reference offshore wind project, and the required power injections starting at the offshore wind turbine generators. A high-voltage direct current scheme would significantly increase costs because onshore and offshore converter stations would be required.

This project accounts for two AC cables of similar size each with a power capacity of approximately 400 MW. Those cables will be XLPE three (3) core with an operating voltage level of 275 kV designed to a voltage class of 300 kV. The submarine export cables will travel approximately 60-miles from the offshore collector station to the onshore landing location. This is based on an average distance for the Massachusetts lease areas shown in Figure 4.1.

A typical installation method was assumed for these cables to maintain reliability while minimizing cost; they will be trenched using a plow guided by a robot rover to create a trench that closes itself as the cable is laid. Each cable will be laid in a separate trench in accordance with the requirement behind the ORTP estimate of providing the low-cost option.

Engineering decisions also focused on the route of the cables from the offshore collector substation platform to the landfall point. The most direct route was determined to cross Rhode Island Sound, travel up the Sakonnet River, and across Mount Hope Bay. A geological study of this routing was outside the scope of this effort given the representative nature of the facility; the cost estimates described below assume this cable routing would be feasible using the plow-

based installation method. If the marine geology ultimately presents more challenging construction circumstances (e.g., New England ledge or granite anywhere along the cabling route), cabling construction and installing methods that are more involved and have a higher cost may be necessary to connect the offshore collector platform to the onshore landing site; alternatively, a different cabling route may be chosen to avoid those challenges. Either approach would raise the cost of this offshore cabling component of the project

Using an average per-mile cost for the 275 kV XLPE three (3) core 1,800 mm² copper cabling and the 60-mile distance from shore, estimated procurement, construction and installation costs for the submarine cabling component of the project is \$583 million (in 2019 dollars). This estimate is based on the data within the Mott MacDonald confidential database, based on the scope described above and adjusted to reflect the modifications specific to this modeled unit.

4.4.5 Landfall and the Transition to Onshore

When the submarine export cable nears the onshore landfall point, the EPC contractor will float part of the cable using specialized barges that are typically used in shallow water. The floating occurs to aid in the horizontal direction drilling (HDD) that will be utilized to send the two 1,800 mm² cables into the onshore transition vault. HDD is an industry-standard way of landing submarine export cables to shore; this method minimizes environmental impacts and disruption to communities, beaches and the shoreline.

The purpose of the landfall transition vault is to transition the offshore cables to onshore cables in the vicinity of the landfall point. It also acts as an anchor when installing the offshore export cables from the shoreside to the offshore substation at the windfarm. The vault is a prefabricated concrete vault that acts as a controlled environment to take the two 3-core submarine export cables and splice them into single-core 275kV 2,000 mm² aluminum cables (6 total) for onshore cabling. This transition uses cheaper cable, as the cables are onshore, and also to gain some current ampacity for increased efficiency.

The \$40 million cost associated with the landfall and the transition vault includes the two prefabricated boxes (one per submarine cable) plus installation, the HDD drill cost and the associated marine and onshore construction activities, and the cable equipment, installation, and splicing costs. This representative estimate is based on the scope provided above and the customization of the data within the Mott MacDonald confidential database.

4.4.6 Project Contingency

A Project Contingency of 5% was added to the total EPC cost to cover any issues or unknowns that may arise for the EPC contractor to manage during the project's construction lifetime, from early development to the operational commencement date. For new technologies, such as offshore wind in the United States, a larger contingency approaching 20% may be appropriate due the larger range of unknowns. However, given the objective of providing an overall cost estimate that is at the lower-end of the competitive cost range, Mott MacDonald assumed a project contingency of 5%.

A project contingency is typically set aside for various types of issues and unforeseeable potential events that may raise the project's costs. Some of the issues that Mott MacDonald has come across in their experience include, but are not limited to:

- Delays in permitting (which can arise in working through requirements of the Bureau of Ocean Energy Management (BOEM), ISO-NE, and Federal, State, County, and/or towns);
- Procurement risk including specialized vessels along with long lead items (i.e., submarine export cables);

- Onshore cabling risk of interfering with existing infrastructure or underground unknowns;
- System reinforcements including underground cables in populated areas and cities;
- Submarine bathymetry and major crossing risks as described in Section 4.4.4;
- Interfaces and project-on-project risk (e.g. it is typical for multiple contractors to be completing work so proper interfacing is critical);
- Availability of skilled labor; and
- Environmental and remediation risks that could arise at any time throughout a project life.

Mott MacDonald has observed some of these risks being realized during recent offshore wind projects, with associated significant increased costs.

4.4.7 Owner's Development Costs

Owner's development costs include the expected costs that the owner will have to account for during the initial development stage of the specified project. Mott MacDonald estimated approximately \$192 million for the owner's development costs, which includes (but is not limited to) costs for the following tasks, as well as a contingency due to the new nature of the offshore wind technology:

- Project management, coordination and other project-based resources that are needed for development progress;
- Stakeholder management and engagement;
- Permitting and environmental assessments;
- Contract management and legal fees;
- Project pre-feasibility and feasibility studies;
- Project management through the construction period;
- Corporate resources cost allocation;
- Wind resource assessments;
- Engineering and design (e.g. system studies, geotechnical studies, conceptual engineering, functional specifications for contracts, initial detailed design); and
- Metocean (the meteorological and oceanographic data relevant for offshore wind facilities) and marine surveys.

All of these tasks are considered typical based on Mott MacDonald observed owner's development costs for other offshore wind projects worldwide.

4.4.8 Onshore Facilities and Electrical Interconnection

Evaluations were conducted of the requirements to bring the undersea cable onshore, through the associated transition vault, and to interconnect with the existing substation and 345 kV network at the Brayton Point POI. Our approach regarding the interconnect was based on our experience with projects in the New England region.

Once the cables are transitioned to the single-core cable, they will travel underground to the developer onshore substation. The purpose of this substation is to increase the voltage from 275kV to 345kV using two (2) 450 MVA transformers. This substation is assumed to also include shunt reactors, STATCOMs, harmonic filters, and their associated control system.

From the developer onshore substation, the onshore 345kV cabling will travel a short distance through underground duct banks (with corresponding fiber optic cables) to the existing 345 kV Brayton Point substation. Mott MacDonald assumed minimum upgrades to the Brayton Point

substation because it is existing and currently has unused connection bays with a large capacity.

The total estimated cost of \$55 million is necessary for the electrical interconnection into the existing Brayton Point Substation with the supporting equipment described above and the associated installation.

This estimate is based on the scope provided above and the customization of the data within the Mott MacDonald confidential database, as well as our extensive experience with substation and electrical projects for power generation. To further support this high-level approach, Mott MacDonald reviewed several electrical studies submitted to ISO-NE, to evaluate the reasonableness of our estimate. This evaluation confirmed the reasonableness of the \$55 million that was estimated for the reference offshore wind project.

4.4.9 Financing Fees

A Financing Fee of 4% of costs financed through debt was included in all of the Mott MacDonald's capital cost estimates for the ISO-NE 2020 CONE and ORTP studies. This assumption was benchmarked against financing fees observed by Mott MacDonald in other offshore wind projects, including 50% of the global worldwide offshore wind projects and 70% of the US offshore wind projects, which are generally reported on a lump-sum basis. The benchmarking supported the reasonableness of the financing fee assumption.

4.4.10 Working Capital

A Working Capital cost of 1% of EPC costs was included; this is consistent with Working Capital assumptions for all of the modeled technologies evaluated for the ISO-NE ORTP study.

4.4.11 Exclusions and Limitations

It is important to observe that the scope of work for the offshore wind project in this engagement did not include a full System Interconnection Study, of the type performed by the professional engineering staff at ISO-NE in the course of evaluating an actual large generator interconnection agreement. As a result, the total interconnection costs for actual future offshore-wind projects may be higher than that estimated in this study. Those costs would be higher if ISO-NE's actual interconnection studies identified a need for transmission system changes and/or upgrades to New England's broader high-voltage transmission system at locations away from the reference offshore wind project's assumed POI at Brayton Point.

An additional important limitation on the scope of work and costs relates to a US law known as the Jones Act, which requires goods shipped between U.S. ports to be transported on ships that are built, owned, and operated by United States citizens or permanent residents. This Act implicates the crewing, origin, registration, and allowed destinations of ships that may be involved in the movement of major equipment or materials, or the construction, of offshore wind facilities. For this cost estimation engagement, Mott did not attempt to ascertain the feasibility of compliance with the Jones Act in the development and construction of an offshore wind project in the Massachusetts lease areas. We highlight this issue because compliance with the Jones Act, given the limited US-built specialized offshore wind construction vessels presently, would likely result in potentially higher project infrastructure costs than those discussed in this report.

4.4.12 Overall Offshore Wind Capital Cost Estimate

The total estimated overnight capital cost value for the representative offshore wind project that is used by CEA in the discounted cash flow model for the offshore wind ORTP calculation is approximately US \$4,286,054,000 (or, for reference, US \$5,358/kW based on the 800 MW of installed capacity).

5 Comparison of Offshore Wind Development Costs

5.1 Introduction

It is important to note that wind projects around the world are executed differently depending on the region or country in which they are built, even when using identical wind turbines. These wind projects are dependent on the prevailing commercial and technical practices, as well as the regulatory requirements and practices specific to the country or region where they are located.

As an example, understanding that projects in China are managed and constructed very differently than those in Western countries leads to the conclusion that projects and estimated data for developments in China are not suitable for comparison to the ISO-NE ORTP offshore wind reference project cost estimation.

Similarly, understanding that the scope of work provided by a European offshore wind project is considerably less than the scope required for a New England project helps us more appropriately develop New England offshore wind project costs, due to such differences (as explained further below). The knowledge and familiarity of our staff with the characteristics of New England offshore wind projects helps to appropriately develop New England-based costs for these projects.

5.2 Global Offshore Wind Comparison

All offshore wind projects have very specific design criteria and scopes based on their specific location (e.g. sea conditions, water depth, distance to POI), detailed technical requirements, local governments (and the resulting regulatory environment), safety and environmental requirements and grid interconnection details. Some of these criteria have a more significant impact than others on the overall project cost.

Different scopes of work, labor costs, and construction practices are three significant factors that can produce a major variance in cost comparisons by location, country or region. For example, labor and construction costs for projects in China are not appropriate for establishing similar costs for Western projects, specifically those in New England, due to different labor laws, engineering standards, engineering methods, different construction practices, as well as different legal requirements. The industry believes that cost data provided by China is not dependable and generally appears to be low. It can be noted that certain public resources (e.g. IRENA) highlight Chinese data in a different color for ready isolation by data users.

A significantly different scope of work for offshore wind projects is prevalent in some European countries as well, when compared to the United States. Some European countries do not include the costs of the offshore substation, the submarine export cabling, the landfall transition, and the electrical interconnect to the POI in the developer's or EPC scope. The reason is that such costs may be funded directly by the European utility, rather than the project developer. As a hypothetical comparison, if those components were (counter to fact) not included in the Mott MacDonald cost estimate for the New England offshore wind reference project, the total overnight capital cost would be reduced by roughly \$1.2 billion, which would reduce the total capital cost estimate to approximately \$3 billion (or, for reference, \$3,750/kW). For this reason, some European project costs, depending on the country, need to be adjusted significantly to

add additional transmission-related work scopes and costs before being compared and contrasted with United States – and specifically with New England – offshore wind project costs. The cost information included with the ISO-NE Offshore Wind ORTP estimates aligns with the ORTP project scope and requirements to deliver 800 MW at the POI in Massachusetts.

An additional scope of work criterion with significant impact in cost is the distance from the offshore substation platform to the POI. As stated above, the POI is at Brayton Point, which is approximately 60 miles from the offshore substation platform and the selected Massachusetts lease area. There are only a few feasible shore-based 345 kV interconnection points in the region. In addition, the offshore wind projects being developed in New England, and the reference project studied here, are far from the POI because the offshore wind lease areas are beyond visual range of all land. In the case of the Massachusetts lease areas, the proximity of Block Island, Rhode Island and Martha's Vineyard, Massachusetts pushed the lease areas further from the main New England coastline.

This "beyond visible range" concept may not be required elsewhere in the world. Several global offshore wind project cost references, including some American references such as the U.S. Energy Information Administration Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies data February 2020 (Page 160 of 212), utilize 25 to 30 miles for their distance from their POI to their offshore substation platform; it is common in Europe to be a maximum of 30 miles offshore, sometime less. There is a significant difference in cost in this assumption. If the ISO-NE offshore wind reference project were to only be 30 miles from the POI, the cost for the export submarine cables would be cut in half (approximately \$292 million which would reduce the overall cost to approximately \$4 billion or \$4,993/kW). Due to this cost variance, Mott MacDonald recommends evaluating the scope of work before one compares the respective reference cost to the ISO-NE offshore wind estimated capital cost.

It is also important to note that costs in Europe have been decreasing over the years; a lot of the decrease is attributable to lessons learned and experience, as well as the regional availability of specialized vessels and supporting onshore infrastructure for staging and construction of offshore wind facilities.

For comparison to the global offshore wind market, the Department of Energy estimates approximately 27,000 MW of offshore wind capacity has been installed as of March 31, 2020³. Of this 27,000 MW, China and Europe represent approximately 22% and 75% of the current global offshore wind installed capacity, respectively (with the US market accounting for roughly 0.2% of the current global offshore wind installed capacity)⁴. Chinese project costs are not a valid comparison to Western project costs because the method of contracting labor and construction practices are not appropriate for a comparison. At this point, the US has little to no experience in the execution of offshore wind projects, and although the US can learn from the rest of the world, the rules and regulations in the US are different and need to be considered. This increases the cost of uncertainties and unknowns that a prudent developer must address, and are included in this bottom-up cost estimate.

5.3 Domestic Offshore Wind Comparison

In addition to cost global cost differences, costs for an offshore wind project can vary between regions of the United States for a number of reasons. As indicated above, costs for projects depend on the scope of work required to achieve project design, as well as operational

³ DOE. 2019 Wind Energy Data & Technology Trends. 2019 Offshore Wind Data – Excel Spreadsheet. Slides 28 and 31. Global data as of March 31, 2020. <u>https://www.energy.gov/eere/wind/2019-wind-energy-data-technology-trends#offshore</u>

⁴ Ibid.

requirements. The primary drivers for these costs for an offshore wind project are the turbine selected, which can be similar with other projects, the locations of the turbines and distance apart, the depth of the water, the type of support structure, and the distance to the POI. For instance, wind turbines are typically separated based on a distance related to their rotor diameters; therefore, the larger the turbine, the longer the distance between the turbines, which in turn requires a larger distance of inter-array cabling.

While regional differences within the U.S. can have a range of impacts on the costs to construct an offshore wind facility, we highlight three differences that are of particular relevance to the cost estimate for a project within New England.

The depth of the water has a large impact on cost for fixed bottom offshore wind projects. The ISO-NE reference offshore wind project is in reasonably deep open water which is more expensive than shallow, easy-to-access locations.

The distance to shore, which in the United States is affected by the requirement to be outside visual range of the shore, pushes the Massachusetts lease areas further from the mainland due to the proximity to Block Island and Martha's Vineyard. As discussed above, longer distance increases costs substantially. This is true for all offshore wind in the United States, but the islands in New England magnify this effect and push the lease areas further off the mainland.

The distance to shore is also affected by the location of the interconnection point. Large 800 MW generator projects need to connect to the high voltage 345kV network to be able to transmit their power to a wide customer base. The New England 345kV network is not located close to the Massachusetts lease areas, so a long undersea cable run is required which significantly increases costs. This will vary depending on location, state to state.



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Attachment I-1g

Affidavit of Danielle S. Powers

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. The information contained in 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 well as the separate March 2021 and April 2021 Addenda thereto 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 April 5, 2021

Dannelle Ann

Danielle S. Powers

Attachment I-1h

Affidavit of Keith Paul
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 27 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, for fossil, nuclear, and renewable generation projects, and documentation of plant performance criteria to ensure target performance and economic 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.
- 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. The information contained in 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 well as the separate March 2021 and April 2021 Addenda thereto is true and correct to the best of my knowledge.
- 6. I was the lead engineer on, and oversaw all the work on, the development of the off-shore wind capital cost analysis that is explained in the Mott MacDonald Off-Shore Wind ORTP Report. I was also the lead author of, and oversaw all aspects of the preparation of, the Mott MacDonald Off-shore Wind ORTP Report. The information contained therein is true and correct to the best of my knowledge.
- 7. I declare, under penalty of perjury, that the foregoing is true and correct.

Executed on April 5, 2021

Knik the

Keith Paul

Attachment I-1i

ISO-NE Marked Tariff Effective June 8, 2021

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 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 (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); (6) with respect to Demand Bids may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Demand Bids may contain multiple sets of quantity and price pairs for each hour); (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 each hour); and (7)

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 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, backto-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 or Non-Market Participant 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.

Offer Review Trigger Prices are the prices specified in Section III.A.21.1 of Market Rule 1 associated with the submission of New Capacity Offers in the Forward Capacity Auction.

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 operation of the responsibilities for the administration Agreement covers the rights and responsibilities for the 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(1) 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 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 enduse 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 Seen 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 systemwide 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
 - 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/kWmonth;
 - (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
 - 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/kWmonth;
 - (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
 - 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/kWmonth

(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 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 $(1 \le m \le 5)$ submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, ..., p_m$, where $P_S > p_1 > p_2 > ... > p_m \ge P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, ..., q_m$. 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:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2$$

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 Commissionapproved 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 Commissionapproved 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 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
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 another bid for the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

Repowering. Offers and bids associated with a resource participating in the Forward Capacity (e) 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.

Conditional Qualified New Resources. Offers associated with a resource participating in the (f) 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:

- 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 importconstrained 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 exportconstrained 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 importconstrained 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]. Referencesin this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward CapacityAuction Starting Price for the Forward Capacity Auction associated with the relevant CapacityCommitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is \$11.978/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is \$7.114/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) (except that the bonus tax depreciation adjustment described in Section

III.A.21.1.2(e)(5) shall not apply). 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 of 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 Periods, as elected pursuant to 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. 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 Commissionapproved 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 Commissionapproved 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.13.1.2.1.2.

(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.13.1.2.2.3 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 Clearing Price in the Rest-of-Pool 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 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 exportconstrained 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 Restof-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.13.1.1.2 (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.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION
APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this *Appendix A*.

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this *Appendix A* shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this *Appendix A*. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor of the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this *Appendix A*.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor and External Market Monitor for and External Market Monitor is created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this *Appendix A*, the provisions of *Appendix A* shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III. A.17.3 are also part of the Participants Agreement and cannot be modified in either *Appendix A* or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this *Appendix A* are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this *Appendix A*). In the event the Internal Market Monitor or External Market Monitor of the states is broader dissemination could lead to exploitation, it shall limit distribution of its

identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

- (b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.
- (c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the External Market Monitor shall perform the following functions:

- (a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this *Appendix A*, in accordance with the provisions of Section III.A.17 of this *Appendix A*.

- (c) Conduct evaluations and prepare reports on its own initiative or at the request of others.
- (d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this *Appendix A*.
- (f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.
- (g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this *Appendix A*, as appropriate.
- (h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the Internal Market Monitor shall perform the following functions:

- (a) Maintain *Appendix A* and consider whether *Appendix A* requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.
- (b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this *Appendix A*.
- (c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this *Appendix A*.
- (d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this *Appendix A*.
- (e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.
- (g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this *Appendix A*.
- (h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

- (i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this *Appendix A*.
- (j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this *Appendix A* are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:
 - (i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.
 - (ii) Uneconomic production from a Resource, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.
 - (iii) Anti-competitive Increment Offers and Decrement Bids, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this Appendix A.
 - (iv) Anti-competitive Demand Bids, which are addressed in Section III.A.10 of this AppendixA.
 - (v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend *Appendix A* as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of

the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

- (k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:
 - (i) Anti-competitive gaming of Resources;
 - (ii) Conduct and market outcomes that are inconsistent with competitive markets;
 - (iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;
 - (iv) Actions in one market that affect price in another market;
 - (v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this *Appendix A*, interfere with efficient market operation, both short-run and long-run; and
 - (vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this *Appendix A*. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this *Appendix A*. If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

- (1) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.
- (m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with *Appendix B* of this Market Rule 1.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this *Appendix A* for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule 1 (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this *Appendix A*. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this *Appendix A*, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under *Appendix B* of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

- (a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:
- (b) Notwithstanding the foregoing or any other provision of this *Appendix A*, and as more fully described in Section III.B.3.2.6 of *Appendix B* to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this *Appendix A*, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this *Appendix A* or in *Appendix B* to this Market Rule 1.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant. In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this Appendix A, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this *Appendix A* for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resourcespecific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer

or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus \$2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of	Months Precluded (starting	
Incidents	from most-recent incident)	
1	2	

2 or more	6
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III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

- (a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
- (b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,
- (c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
- (d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

- (a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
- (b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

- (a) all Supply Offer parameters shall be reviewed for economic withholding;
- (b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;
- (c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

- (a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;
- (b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

- (a) for purposes of the Real-Time Energy Market, the Resource is located on the importconstrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;
- (b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than \$25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

- (a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
- (b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or \$100/MWh, whichever is lower. Offer block prices below \$25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or \$100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or \$25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or \$25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

- i. local first contingency;
- ii. local second contingency;
- iii. VAR or voltage;
- iv. distribution (Special Constraint Resource Service);
- v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

- (a) If the Resource is starting from an offline state, the Start-Up Fee;
- (b) The sum of the No Load Fees for the Commitment Period; and
- (c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 "General Threshold Energy Mitigation" or III.A.5.5.2 "Constrained Area Energy Mitigation" is in effect for the following duration:

- (a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:
 - i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,
 - ii. for constrained area energy mitigation, the Resource is not located within a constrained area.
- (b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 "Constrained Area Energy Mitigation"), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 "Manual Dispatch Energy Mitigation" is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource's Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 "General Threshold Commitment Mitigation", III.A.5.5.5 "Constrained Area Commitment Mitigation", or III.A.5.5.6 "Reliability Commitment Mitigation" is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 "Start-Up Fee and No-Load Fee Mitigation" is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as

part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a startup state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

Market Participants are responsible for providing the Internal Market Monitor with all the information and data necessary for the Internal Market Monitor to calculate up-to-date Reference Levels for each of a Market Participant's Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

- (a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.
- (b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.
- (c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, Interruption Costs and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of an offer according to the following hierarchy, under which the first method that can be calculated is used:

- (a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
- (b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
- (c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

- (a) When in any hour the cost-based Reference Level is higher than either the accepted offerbased or LMP-based Reference Level.
- (b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
- (c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
- (d) For any Operating Day for which, during the previous 90 days:
 - the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
 - (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
- (e) When in any hour the incremental energy parameter of an offer, including adjusted offers pursuant to Section III.2.4, is greater than \$1,000/MWh.

For the purposes of this subsection:

- A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.
- ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.
- iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.
- iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.
- (e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.
- (f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:
 - (i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,
 - (ii) No-Load Fee or its corresponding fuel blends,
 - (iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,
 - (iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and
 - (v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

- (a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".
- (b) Costs must be documented.
- (c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible. All cost estimates, including opportunity cost estimates, must be quantified and analytically supported.
- (d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.
- (e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

- Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and
- ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy/Reduction:

(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

- (a) emissions limits;
- (b) water storage limits;
- (c) other operating permits that limit production of energy; and
- (d) reducing electricity consumption.

No-Load:

(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up/Interruption:

(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. [Reserved.]

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor the Energy Market as outlined below:

- (a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.
- (b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: (LMP real time / LMP day ahead) – 1. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.
- (c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between

the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as: $(LMP_{real time} / LMP_{day ahead}) - 1$.

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.
If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

- (i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.
- Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.
- (iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations is greater than the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the

number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

- (a) [Reserved].
- (b) Section III.13.1.2.3.1.6.3 Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.
- (c) Section III.13.1.2.3.2 Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.
- (d) Section III.13.1.3.3A(d) Review by Internal Market Monitor of offers from Existing Import Capacity Resources.
- (e) Section III.13.1.3.5.6 Review by Internal Market Monitor of Offers from New Import Capacity Resources.
- (f) Section III.13.1.7 Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this *Appendix A*. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer *Appendix B* in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement. Article 5 of the form of Cost-of-Service Agreement in *Appendix I* to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Market Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Cost Recovery Request Following Capping.

If as a result of an offer being capped under Section III.1.9, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was capped, the Market Participant may, within 20 days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit an additional cost recovery request to the Internal Market Monitor.

A request under this Section III.A.15 may seek recovery of additional costs incurred for the duration of the period of time for which the Resource was operated at the cap.

III.A.15.1.1. Timing and Contents of Request.

Within 20 days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant requesting additional cost recovery under this Section III.A.15.1 shall submit to the Internal Market Monitor a request in writing detailing: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data, documentation and calculations for those costs; and (ii) an explanation of why the actual costs of operating the Resource exceeded the capped costs.

III.A.15.1.2. Review by Internal Market Monitor.

To evaluate a Market Participant's request, the Internal Market Monitor shall use the data, calculations and explanations provided by the Market Participant to verify the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, using the same standards and methodologies the Internal Market Monitor uses to evaluate requests to update Reference Levels under Section III.A.3 of Appendix A. To the extent the Market Participant's request warrants additional cost recovery, the Internal Market Monitor shall reflect that adjustment in the Resource's Reference Levels for the period covered by the request. The ISO shall then re-apply the cost verification and capping formulas in Section III.1.9 using the updated Reference Levels to re-calculate the adjustments to the Market Participant's offers required thereunder, and then shall calculate additional cost recovery using the adjusted offer values.

Within 20 days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the Market Participant's request, detailing (i) the extent to which it agrees with the request with supporting explanation, and (ii) a calculation of the additional cost recovery. Changes to

credits and charges resulting from an additional cost recovery request shall be included in the Data Reconciliation Process.

III.A.15.1.3. Cost Allocation.

The ISO shall allocate charges to Market Participants for payment of any additional cost recovery granted under this Section III.A.15.1 in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.15.2. Section 205 Filing Right.

If either

(a) as a result of mitigation applied to a Resource under this *Appendix A* for all or part of one or more Operating Days, or

(b) in the absence of mitigation, as a result of a request under Section III.A.15.1 being denied in whole or in part,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was mitigated or the Section III.A.15.1 request was denied, the Market Participant may submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. For filings to address cost recovery under Section III.A.15.2(a), the filing must be made within sixty days of receipt of the first Invoice issued containing credits or charges for the applicable Operating Day. For filings to address cost recovery under Section III.A.15.2(b), the filing must be made within sixty days of receipt of the first Invoice issued that reflects the denied request for additional cost recovery under Section III.A.15.1.

A request under this Section III.A.15.2 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having a Section III.A.15.1 request denied, costs incurred for the duration of the period of time addressed in the Section III.A.15.1 request.

III.A.15.2.1. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data

and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource, as reflected in the original offer and to the extent not recovered under Section III.A.15.1, exceeded the costs as reflected in the capped offer; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.2.2. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the applicable Invoice, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15.2 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2.1 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15.2 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.2.

III.A.15.2.3. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in *Appendix D* to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

• Imposition of a mitigation remedy.

• Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this *Appendix A*, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

- (a) the opportunity costs associated with Demand Reduction Offers;
- (b) the accuracy of Demand Response Baselines;
- (c) the method used to achieve a demand reduction, and;
- (d) the accuracy of metered demand reported to the ISO.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this Appendix A and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this Appendix A.

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this *Appendix A*.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of *Appendix A*. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

- Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.
- (ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.
- (iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.
- (iv) Review and assessment of the effectiveness of *Appendix A* and the administration of *Appendix A* by the Internal Market Monitor for consistency and compliance with the terms of *Appendix A*.
- Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

- (a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;
- (b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;
- (c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,
- (d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). With respect to state regulatory bodies and state attorneys general ("authorized state agencies"), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government

agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as *Exhibit 5*.

III.A.18.2. Additional Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of *Appendix A*, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

- (B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information
 - The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);
 - (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
 - (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
 - (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
 - (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;
 - (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
 - (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

- (A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.
- (B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information.
 - (1) A detailed narrative describing the perceived market design flaw(s);
 - (2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;
 - (3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;
 - (4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the twelfth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 202<u>5</u>1) shall be as follows:

Generating Capacity Resources	
Technology Type	Offer Review Trigger Price (\$/kW-month)
Simple Cycle eCombustion ETurbine	\$ <u>5.355</u> 6.503
eCombined eCycle gGas tTurbine	\$ <u>9.811</u> 7 .856
● <u>O</u> n- sS hore ₩ <u>W</u> ind	\$ <u>0.000</u> 11.025
<u>Energy Storage Device – Lithium Ion</u> <u>Battery</u>	<u>\$2.9122.923</u>
Photovoltaic Solar	<u>\$1.381</u>

Demand Capacity Resources - Commercial and Industrial		
Technology Type	Offer Review Trigger Price (\$/kW-month)	
Load Management <u>(Commercial /</u> <u>Industrial)and/or previously installed</u> Distributed Generation	\$ <u>0.750</u> 1.008	
Previously Installed Distributed Generation	<u>\$0.750</u>	
nNew Distributed Generation	b <u>B</u> ased on generation technology type	
On-Peak Solar	<u>\$5.414</u>	

Demand Capacity Resources Residential	
Technology Type	Offer Review Trigger Price (\$/kW-month)
Load Management	\$7.559
previously installed Distributed Generation	\$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	\$0.000

Other Resources	
All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For 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, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus \$0.01/kW-month. For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. 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.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy

Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) ______For the simple cycle combustion turbine and combined cycle gas turbine technology types, Eeach line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114). For all other Generating Capacity Resource technology types, each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the levelized cost of energy for that technology as published by Bloomberg.associated with the indices included in the table below:

Cost Component	Index
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"
steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS "Quarterly Census of Employment and Wages" 2371 Utility
	System Construction Average Annual Pay:
	 Combustion turbine and combined cycle gas turbine costs
	to be indexed to values corresponding to the location of
	Hampden County, Massachusetts
	 On shore wind costs to be indexed to values corresponding
	to the location of Cumberland County, Maine
other labor	BLS "Quarterly Census of Employment and Wages" 2211 Power
	Generation and Supply Average Annual Pay:
	 Combustion turbine and combined cycle gas turbine costs
	to be indexed to values corresponding to the location of
	Hampden County, Massachusetts
	 On-shore wind costs to be indexed to values corresponding
	to the location of Cumberland County, Maine
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"

gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate
	consumers for the account of others (transportation only)"
fuel inventories	Federal Reserve Bank of St. Louis "Gross Domestic Product:
	Implicit Price Deflator (GDPDEF)"

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	Index
labor, administrative and	BLS "Quarterly Census of Employment and Wages" 2211 Power
general	Generation and Supply Average Annual Pay:
	 Combustion turbine and combined cycle gas turbine costs
	to be indexed to values corresponding to the location of
	Hampden County, Massachusetts
	 On shore wind costs to be indexed to values corresponding
	to the location of Cumberland County, Maine
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis "Gross Domestic Product:
	Implicit Price Deflator (GDPDEF)"

(32) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the FCA-reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 above will be adjusted by the relevant multiplier.

(4<u>3</u>) The energy and ancillary services offset values for <u>gas each</u> technology type<u>s</u> in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the <u>most recent</u> Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub <u>Day-Ahead Peak On Peak electricity prices, as published by ICE for the first five trading days in</u> <u>February, for each the months in the Capacity Commitment Period beginning June 1 of the Capacity</u> <u>Commitment Period to which the updated value will apply, 2021, as published by ICE</u>.

The energy and ancillary services offset values for non-gas technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE for the first five trading days in February, for each month of the Capacity Commitment Period to which the updated value will apply. (54) Renewable energy credit values in the capital budgeting model shall be updated based on the <u>first</u> most recent MA Class 1 REC prices <u>published in February</u> for the <u>five</u> vintages closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(5) The bonus tax depreciation adjustment included in the financial model for the Offer Review Trigger Prices (which is 40 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 20 percent for the Capacity Commitment Period beginning on June 1, 2026, and zero for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(6) The investment tax credit adjustment included in the financial model for the Offer Review Trigger Prices for the photovoltaic solar Generating Capacity Resource technology type (which is 26 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 22 percent for the Capacity Commitment Period beginning on June 1, 2026, and 10 percent for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(67) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(78) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in

transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be \$0.00/kW-month.

For 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, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of 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 calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's gualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

- (a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;
- (b) For each modeled import-constrained Capacity Zone, the greater of:
 - (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;
 - (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
- (c) For each modeled nested export-constrained Capacity Zone, the lesser of:
 - (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the nested export-constrained Capacity Zone plus, for each external interface connected to the nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;
 - (2) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;
- (d) For each modeled export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, the lesser of:
 - (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone, excluding the total FCA Qualified Capacity from Existing Generating Capacity Resources and Existing Demand Capacity Resources within a nested export-constrained Capacity Zone, plus, for each external interface connected to the export-constrained Capacity Zone that is not included in any nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, excluding the contribution from any nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;
 - (2) the Maximum Capacity Limit of the export-constrained Capacity Zone minus the contribution from any associated nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

- (e) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of:
 - (1) the capacity transfer limit of the interface (net of tie benefits), and;
 - (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

- The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone; and
- (2) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

- (a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone or nested export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone or nested export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.
- (b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one

price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Capacity Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) 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; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any 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; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

- The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than
- the annual capacity revenue from the Lead Market Participant's total FCA Qualified
 Capacity, including the FCA Qualified Capacity associated with the Permanent De-List
 Bid or Retirement De-List Bid, then
- iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

- iv. the Lead Market Participant's annual capacity revenue from the Lead Market
 Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity
 associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the
 product of (a) the Lead Market Participant's total FCA Qualified Capacity not including
 the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement
 De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not
 including the FCA Qualified Capacity associated with the Permanent De-List Bid or
 Retirement De-List Bid.
- v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.
- vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

If

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

Attachment I-1j

ISO-NE Clean Tariff Effective June 8, 2021

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 (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); (6) with respect to Demand Bids may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Demand Bids may contain multiple sets of quantity and price pairs for each hour); (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 each hour); and (7)

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 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, backto-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 or Non-Market Participant 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.

Offer Review Trigger Prices are the prices specified in Section III.A.21.1 of Market Rule 1 associated with the submission of New Capacity Offers in the Forward Capacity Auction.

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 operation of the responsibilities for the administration Agreement covers the rights and responsibilities for the 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(1) 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 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 enduse 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 Seen 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 systemwide 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
 - 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/kWmonth;
 - (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
 - 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/kWmonth;
 - (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
 - 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/kWmonth

(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 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 $(1 \le m \le 5)$ submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, ..., p_m$, where $P_S > p_1 > p_2 > ... > p_m \ge P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, ..., q_m$. 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:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2$$

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 Commissionapproved 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 Commissionapproved 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 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

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 another bid for the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

Repowering. Offers and bids associated with a resource participating in the Forward Capacity (e) 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.

Conditional Qualified New Resources. Offers associated with a resource participating in the (f) 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:

- 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 importconstrained 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 exportconstrained 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 importconstrained 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]. Referencesin this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward CapacityAuction Starting Price for the Forward Capacity Auction associated with the relevant CapacityCommitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is \$11.978/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is \$7.114/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) (except that the bonus tax depreciation adjustment described in Section

III.A.21.1.2(e)(5) shall not apply). 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 of 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 Periods, as elected pursuant to 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. 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 Commissionapproved 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 Commissionapproved 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.13.1.2.1.2.

(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.13.1.2.2.3 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 Clearing Price in the Rest-of-Pool 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 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 exportconstrained 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 Restof-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.13.1.1.2 (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.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this *Appendix A*.

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this *Appendix A* shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this *Appendix A*. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor of the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this *Appendix A*.
This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor and External Market Monitor for an External Market Monitor is confidential to be its with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this *Appendix A*, the provisions of *Appendix A* shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III. A.17.3 are also part of the Participants Agreement and cannot be modified in either *Appendix A* or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this *Appendix A* are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this *Appendix A*). In the event the Internal Market Monitor or External Market Monitor of the states is broader dissemination could lead to exploitation, it shall limit distribution of its

identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

- (b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.
- (c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the External Market Monitor shall perform the following functions:

- (a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this *Appendix A*, in accordance with the provisions of Section III.A.17 of this *Appendix A*.

- (c) Conduct evaluations and prepare reports on its own initiative or at the request of others.
- (d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this *Appendix A*.
- (f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.
- (g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this *Appendix A*, as appropriate.
- (h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the Internal Market Monitor shall perform the following functions:

- (a) Maintain *Appendix A* and consider whether *Appendix A* requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.
- (b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this *Appendix A*.
- (c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this *Appendix A*.
- (d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this *Appendix A*.
- (e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.
- (g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this *Appendix A*.
- (h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

- (i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this *Appendix A*.
- (j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this *Appendix A* are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:
 - (i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.
 - (ii) Uneconomic production from a Resource, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.
 - (iii) Anti-competitive Increment Offers and Decrement Bids, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this Appendix A.
 - (iv) Anti-competitive Demand Bids, which are addressed in Section III.A.10 of this AppendixA.
 - (v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend *Appendix A* as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of

the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

- (k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:
 - (i) Anti-competitive gaming of Resources;
 - (ii) Conduct and market outcomes that are inconsistent with competitive markets;
 - (iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;
 - (iv) Actions in one market that affect price in another market;
 - (v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this *Appendix A*, interfere with efficient market operation, both short-run and long-run; and
 - (vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this *Appendix A*. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this *Appendix A*. If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

- (1) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.
- (m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with *Appendix B* of this Market Rule l.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this *Appendix A* for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule 1 (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this *Appendix A*. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this *Appendix A*, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under *Appendix B* of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

- (a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:
- (b) Notwithstanding the foregoing or any other provision of this *Appendix A*, and as more fully described in Section III.B.3.2.6 of *Appendix B* to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This Appendix A.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this *Appendix A*, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this *Appendix A* or in *Appendix B* to this Market Rule 1.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant. In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this Appendix A, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this *Appendix A* for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resourcespecific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer

or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus \$2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of	Months Precluded (starting
Incidents	from most-recent incident)
1	2

2 or more	6
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III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

- (a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
- (b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,
- (c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
- (d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

- (a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
- (b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

- (a) all Supply Offer parameters shall be reviewed for economic withholding;
- (b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;
- (c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

- (a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;
- (b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

- (a) for purposes of the Real-Time Energy Market, the Resource is located on the importconstrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;
- (b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than \$25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

- (a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
- (b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or \$100/MWh, whichever is lower. Offer block prices below \$25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or \$100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or \$25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or \$25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

- i. local first contingency;
- ii. local second contingency;
- iii. VAR or voltage;
- iv. distribution (Special Constraint Resource Service);
- v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

- (a) If the Resource is starting from an offline state, the Start-Up Fee;
- (b) The sum of the No Load Fees for the Commitment Period; and
- (c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 "General Threshold Energy Mitigation" or III.A.5.5.2 "Constrained Area Energy Mitigation" is in effect for the following duration:

- (a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:
 - i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,
 - ii. for constrained area energy mitigation, the Resource is not located within a constrained area.
- (b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 "Constrained Area Energy Mitigation"), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 "Manual Dispatch Energy Mitigation" is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource's Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 "General Threshold Commitment Mitigation", III.A.5.5.5 "Constrained Area Commitment Mitigation", or III.A.5.5.6 "Reliability Commitment Mitigation" is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 "Start-Up Fee and No-Load Fee Mitigation" is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as

part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a startup state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

Market Participants are responsible for providing the Internal Market Monitor with all the information and data necessary for the Internal Market Monitor to calculate up-to-date Reference Levels for each of a Market Participant's Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

- (a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.
- (b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.
- (c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, Interruption Costs and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of an offer according to the following hierarchy, under which the first method that can be calculated is used:

- (a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
- (b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
- (c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

- (a) When in any hour the cost-based Reference Level is higher than either the accepted offerbased or LMP-based Reference Level.
- (b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
- (c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
- (d) For any Operating Day for which, during the previous 90 days:
 - the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
 - (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
- (e) When in any hour the incremental energy parameter of an offer, including adjusted offers pursuant to Section III.2.4, is greater than \$1,000/MWh.

For the purposes of this subsection:

- A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.
- ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.
- iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.
- iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.
- (e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.
- (f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:
 - (i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,
 - (ii) No-Load Fee or its corresponding fuel blends,
 - (iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,
 - (iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and
 - (v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

- (a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".
- (b) Costs must be documented.
- (c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible. All cost estimates, including opportunity cost estimates, must be quantified and analytically supported.
- (d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.
- (e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

- Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and
- ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy/Reduction:

(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

- (a) emissions limits;
- (b) water storage limits;
- (c) other operating permits that limit production of energy; and
- (d) reducing electricity consumption.

No-Load:

(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up/Interruption:

(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. [Reserved.]

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor the Energy Market as outlined below:

- (a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.
- (b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: (LMP real time / LMP day ahead) – 1. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.
- (c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between

the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as: $(LMP_{real time} / LMP_{day ahead}) - 1.$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

- (i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.
- Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.
- (iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations is greater than the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the

number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

- (a) [Reserved].
- (b) Section III.13.1.2.3.1.6.3 Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.
- (c) Section III.13.1.2.3.2 Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.
- (d) Section III.13.1.3.3A(d) Review by Internal Market Monitor of offers from Existing Import Capacity Resources.
- (e) Section III.13.1.3.5.6 Review by Internal Market Monitor of Offers from New Import Capacity Resources.
- (f) Section III.13.1.7 Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this *Appendix A*. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer *Appendix B* in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement. Article 5 of the form of Cost-of-Service Agreement in *Appendix I* to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Market Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Cost Recovery Request Following Capping.

If as a result of an offer being capped under Section III.1.9, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was capped, the Market Participant may, within 20 days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit an additional cost recovery request to the Internal Market Monitor.

A request under this Section III.A.15 may seek recovery of additional costs incurred for the duration of the period of time for which the Resource was operated at the cap.

III.A.15.1.1. Timing and Contents of Request.

Within 20 days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant requesting additional cost recovery under this Section III.A.15.1 shall submit to the Internal Market Monitor a request in writing detailing: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data, documentation and calculations for those costs; and (ii) an explanation of why the actual costs of operating the Resource exceeded the capped costs.

III.A.15.1.2. Review by Internal Market Monitor.

To evaluate a Market Participant's request, the Internal Market Monitor shall use the data, calculations and explanations provided by the Market Participant to verify the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, using the same standards and methodologies the Internal Market Monitor uses to evaluate requests to update Reference Levels under Section III.A.3 of Appendix A. To the extent the Market Participant's request warrants additional cost recovery, the Internal Market Monitor shall reflect that adjustment in the Resource's Reference Levels for the period covered by the request. The ISO shall then re-apply the cost verification and capping formulas in Section III.1.9 using the updated Reference Levels to re-calculate the adjustments to the Market Participant's offers required thereunder, and then shall calculate additional cost recovery using the adjusted offer values.

Within 20 days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the Market Participant's request, detailing (i) the extent to which it agrees with the request with supporting explanation, and (ii) a calculation of the additional cost recovery. Changes to

credits and charges resulting from an additional cost recovery request shall be included in the Data Reconciliation Process.

III.A.15.1.3. Cost Allocation.

The ISO shall allocate charges to Market Participants for payment of any additional cost recovery granted under this Section III.A.15.1 in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.15.2. Section 205 Filing Right.

If either

(a) as a result of mitigation applied to a Resource under this *Appendix A* for all or part of one or more Operating Days, or

(b) in the absence of mitigation, as a result of a request under Section III.A.15.1 being denied in whole or in part,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was mitigated or the Section III.A.15.1 request was denied, the Market Participant may submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. For filings to address cost recovery under Section III.A.15.2(a), the filing must be made within sixty days of receipt of the first Invoice issued containing credits or charges for the applicable Operating Day. For filings to address cost recovery under Section III.A.15.2(b), the filing must be made within sixty days of receipt of the first Invoice issued that reflects the denied request for additional cost recovery under Section III.A.15.1.

A request under this Section III.A.15.2 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having a Section III.A.15.1 request denied, costs incurred for the duration of the period of time addressed in the Section III.A.15.1 request.

III.A.15.2.1. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data

and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource, as reflected in the original offer and to the extent not recovered under Section III.A.15.1, exceeded the costs as reflected in the capped offer; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.2.2. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the applicable Invoice, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15.2 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2.1 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15.2 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.2.

III.A.15.2.3. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in *Appendix D* to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

• Imposition of a mitigation remedy.

• Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this *Appendix A*, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:
- (a) the opportunity costs associated with Demand Reduction Offers;
- (b) the accuracy of Demand Response Baselines;
- (c) the method used to achieve a demand reduction, and;
- (d) the accuracy of metered demand reported to the ISO.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this Appendix A and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this Appendix A.

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this *Appendix A*.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of *Appendix A*. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

- Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.
- (ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.
- (iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.
- (iv) Review and assessment of the effectiveness of *Appendix A* and the administration of *Appendix A* by the Internal Market Monitor for consistency and compliance with the terms of *Appendix A*.
- Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

- (a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;
- (b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;
- (c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,
- (d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). With respect to state regulatory bodies and state attorneys general ("authorized state agencies"), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government

agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as *Exhibit 5*.

III.A.18.2. Additional Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of *Appendix A*, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

- (B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information
 - The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);
 - (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
 - (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
 - (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
 - (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;
 - (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
 - (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

- (A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.
- (B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information.
 - (1) A detailed narrative describing the perceived market design flaw(s);
 - (2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;
 - (3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;
 - (4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the Capacity Commitment Period beginning on June 1, 2025 shall be as follows:

Generating Capacity Resources			
Technology Type	Offer Review Trigger Price (\$/kW-month)		
Simple Cycle Combustion Turbine	\$5.355		
Combined Cycle Gas Turbine	\$9.811		
On-Shore Wind	\$0.000		
Energy Storage Device – Lithium Ion Battery	\$2.912		
Photovoltaic Solar	\$1.381		

Demand Capacity Resources			
Technology Type	Offer Review Trigger Price (\$/kW-month)		
Load Management (Commercial / Industrial)	\$0.750		
Previously Installed Distributed Generation	\$0.750		
New Distributed Generation	Based on generation technology type		
On-Peak Solar	\$5.414		
Energy Efficiency	\$0.000		

Other Resources			
All other technology types	Forward Capacity Auction Starting Price		

Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For 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, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. 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.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) For the simple cycle combustion turbine and combined cycle gas turbine technology types, each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114). For all other Generating Capacity Resource technology types, each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the levelized cost of energy for that technology as published by Bloomberg.

(2) For each line item in (1) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices reflected in the table in Section III.A.21.1.1. The value of each line item associated with capital costs in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 will be adjusted by the relevant multiplier.

(3) The energy and ancillary services offset values for gas technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE for the first five trading days in February, for each month of the Capacity Commitment Period to which the updated value will apply.

The energy and ancillary services offset values for non-gas technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE for the first five trading days in February, for each month of the Capacity Commitment Period to which the updated value will apply.

(4) Renewable energy credit values in the capital budgeting model shall be updated based on the first MA Class 1 REC prices published in February for the five vintages closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(5) The bonus tax depreciation adjustment included in the financial model for the Offer Review Trigger Prices (which is 40 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 20

percent for the Capacity Commitment Period beginning on June 1, 2026, and zero for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(6) The investment tax credit adjustment included in the financial model for the Offer Review Trigger Prices for the photovoltaic solar Generating Capacity Resource technology type (which is 26 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 22 percent for the Capacity Commitment Period beginning on June 1, 2026, and 10 percent for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(7) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection(e) will be published on the ISO's web site.

(8) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be \$0.00/kW-month.

For 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, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of 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 calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its

requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

- (a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;
- (b) For each modeled import-constrained Capacity Zone, the greater of:
 - the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii)

the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;

- (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
- (c) For each modeled nested export-constrained Capacity Zone, the lesser of:
 - (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the nested export-constrained Capacity Zone plus, for each external interface connected to the nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;
 - (2) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;
- (d) For each modeled export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, the lesser of:
 - (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone, excluding the total FCA Qualified Capacity from Existing Generating Capacity Resources and Existing Demand Capacity Resources within a nested export-constrained Capacity Zone, plus, for each external interface connected to the export-constrained Capacity Zone that is not included in any nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, excluding the contribution from any nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;
 - (2) the Maximum Capacity Limit of the export-constrained Capacity Zone minus the contribution from any associated nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;
- (e) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of:
 - (1) the capacity transfer limit of the interface (net of tie benefits), and;
 - (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

- The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone; and
- (2) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

- (a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone or nested export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone or nested export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.
- (b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Capacity Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) 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; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any 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; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

- The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than
- the annual capacity revenue from the Lead Market Participant's total FCA Qualified
 Capacity, including the FCA Qualified Capacity associated with the Permanent De-List
 Bid or Retirement De-List Bid, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

- iv. the Lead Market Participant's annual capacity revenue from the Lead Market
 Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity
 associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the
 product of (a) the Lead Market Participant's total FCA Qualified Capacity not including
 the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement
 De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not
 including the FCA Qualified Capacity associated with the Permanent De-List Bid or
 Retirement De-List Bid.
- v. The Lead Market Participant's annual capacity revenue from the Lead Market
 Participant's total FCA Qualified Capacity including the FCA Qualified Capacity
 associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the
 product of (a) the Lead Market Participant's total FCA Qualified Capacity including the
 FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including
 the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement
 De-List Bid.
- vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

Attachment I-1k

List of New England Governors and Utility Regulatory Agencies

New England Governors, State Utility Regulators and Related Agencies*

Connecticut

The Honorable Ned Lamont Office of the Governor State Capitol 210 Capitol Ave. Hartford, CT 06106 bob.clark@ct.gov

Connecticut Attorney General's Office 165 Capitol Avenue Hartford, CT 06106 John.wright@ct.gov Lauren.bidra@ct.gov

Connecticut Department of Energy and Environmental Protection 79 Elm Street Hartford, CT 06106 <u>Eric.annes@ct.gov</u> <u>Robert.snook@ct.gov</u>

Connecticut Public Utilities Regulatory Authority 10 Franklin Square New Britain, CT 06051-2605 <u>steven.cadwallader@ct.gov</u> <u>robert.luysterborghs@ct.gov</u> <u>Seth.Hollander@ct.gov</u> Robert.Marconi@ct.gov

Maine

The Honorable Janet Mills One State House Station Office of the Governor Augusta, ME 04333-0001 Jeremy.kennedy@maine.gov Elise.baldacci@maine.gov

Maine Public Utilities Commission 18 State House Station Augusta, ME 04333-0018 Maine.puc@maine.gov

Massachusetts

The Honorable Charles Baker Office of the Governor State House Boston, MA 02133 Massachusetts Attorney General's Office One Ashburton Place Boston, MA 02108 <u>rebecca.tepper@state.ma.us</u>

Massachusetts Department of Energy Resources 100 Cambridge Street, Suite 1020 Boston, MA 02114 <u>Robert.hoaglund@mass.gov</u> <u>ben.dobbs@state.ma.us</u>

Massachusetts Department of Public Utilities One South Station Boston, MA 02110 <u>Nancy.Stevens@state.ma.us</u> <u>morgane.treanton@state.ma.us</u> <u>William.J.Anderson2@mass.gov</u> <u>dpu.electricsupply@mass.gov</u>

New Hampshire

The Honorable Chris Sununu Office of the Governor 26 Capital Street Concord NH 03301

New Hampshire Office of Strategic Initiatives 107 Pleasant Street Concord, NH 03301 Jared.chicoine@nh.gov

New Hampshire Public Utilities Commission 21 South Fruit Street, Ste. 10 Concord, NH 03301-2429 tom.frantz@puc.nh.gov george.mccluskey@puc.nh.gov New Hampshire PUC, continued David.Shulock@puc.nh.gov David.goyette@puc.nh.gov RegionalEnergy@puc.nh.gov kate.bailey@puc.nh.gov amanda.noonan@puc.nh.gov Corrine.lemay@puc.nh.gov

New England Governors, State Utility Regulators and Related Agencies*

Rhode Island

The Honorable Daniel McKee Office of the Governor 82 Smith Street Providence, RI 02903 Rosemary.powers@governor.ri.gov

Rhode Island Office of Energy Resources One Capitol Hill Providence, RI 02908 <u>christopher.kearns@energy.ri.gov</u> <u>nicholas.ucci@energy.ri.gov</u>

Rhode Island Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888 <u>ronald.gerwatowski@puc.ri.gov</u> <u>todd.bianco@puc.ri.gov</u> Marion.Gold@puc.ri.gov

Vermont

The Honorable Phil Scott Office of the Governor 109 State Street, Pavilion Montpelier, VT 05609 jason.gibbs@vermont.gov

Vermont Public Utility Commission 112 State Street Montpelier, VT 05620-2701 <u>mary-jo.krolewski@vermont.gov</u> <u>sarah.hofmann@vermont.gov</u> Margaret.cheney@vermont.gov

Vermont Department of Public Service 112 State Street, Drawer 20 Montpelier, VT 05620-2601 <u>bill.jordan@vermont.gov</u> <u>june.tierney@vermont.gov</u> <u>Ed.McNamara@vermont.gov</u>

New England Governors, Utility Regulatory and Related Agencies

Jay Lucey Coalition of Northeastern Governors 400 North Capitol Street, NW, Suite 370 Washington, DC 20001 coneg@sso.org Heather Hunt, Executive Director New England States Committee on Electricity 424 Main Street Osterville, MA 02655 <u>HeatherHunt@nescoe.com</u> <u>JasonMarshall@nescoe.com</u> JeffBentz@nescoe.com

Meredith Hatfield, Executive Director New England Conference of Public Utilities Commissioners 72 N. Main Street Concord, NH 03301 <u>mhatfield@necpuc.org</u>

Ron Gerwatowksi, President New England Conference of Public Utilities Commissioners 89 Jefferson Blvd. Warwick, RI 02888 <u>ronald.gerwatowski@puc.ri.gov</u> Attachment N-1a

NEPOOL Transmittal Letter

April 7, 2021



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. and New England Power Pool, Docket No. ER21-___-000; NEPOOL's Proposed ORTP Values and Related Tariff Revisions

Dear Secretary Bose:

The New England Power Pool (NEPOOL)¹ Participants Committee² submits for inclusion in a joint filing with ISO New England Inc. (ISO-NE or the ISO) the NEPOOL-approved set of Offer Review Trigger Prices (ORTPs) and related Tariff revisions, referred to as the "NEPOOL Alternative." The NEPOOL Alternative reflects New England stakeholders' preferred set of revisions to the ISO's favored set of ORTPs, referred to here as "the ISO ORTP Proposal."

The instant Section 205 filing updates ORTP values to be used in the ISO's administration of New England's Forward Capacity Market (FCM) beginning with the sixteenth Forward Capacity Auction (FCA 16). The ISO ORTP Proposal, which is described in detail in the ISO's filing materials, failed to garner the requisite aggregate Sector Voting Shares needed for NEPOOL support, with only a 19.04% Vote in favor (a 60% Vote is required for NEPOOL approval).

The NEPOOL Alternative addresses certain aspects of the ISO ORTP Proposal with several enhancements that were approved by a supermajority of the NEPOOL members. In stark contrast to the 19.04% support for the ISO's proposal, the NEPOOL Alternative received a

¹ NEPOOL provides the Commission-approved stakeholder advisory process for the New England RTO and is authorized to represent its more than 510 members in proceedings before the Commission. *See* Second Restated NEPOOL Agreement § 6.1; Participants Agreement § 8.1.3(c). As a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, its members include all of the electric utilities rendering or receiving services under the ISO-NE Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users and a merchant transmission provider.

² Capitalized terms not defined herein have the meanings ascribed in the Second Restated NEPOOL Agreement, Participants Agreement, or the ISO-NE Transmission, Markets and Services Tariff (the ISO-NE Tariff or Tariff). Section III of the ISO-NE Tariff is referred to as "Market Rule 1."

72.50% Vote in favor, with support registered from all six Sectors in NEPOOL.³ As a result of this vote outcome and pursuant to Section 11.1.5 of the Participants Agreement, the NEPOOL Alternative is filed on the same legal footing as the ISO's proposal, providing the Commission with sufficiently broad latitude to select a preferred outcome that will benefit market participants and consumers alike.

In addition to this transmittal letter, NEPOOL offers the following materials in support of the NEPOOL Alternative:⁴

- Attachment N-1b: Testimony of Ms. Abigail Krich, President, Boreas Renewables, LLC, (Krich Testimony), including Appendices A and B;
 Attachment N-1c: Testimony of Ms. Carolyn Gilbert, Managing Consultant, Daymark Energy Advisors (Gilbert Testimony), including Appendices A and B;
 Attachment N-1d: Joint Testimony of Ms. Elizabeth Delaney, Director of Wholesale Market Development, Borrego Solar Systems, Inc., and Dr. Michael Macrae, Senior Manager of Regulatory Affairs for the Northeast, Enel X North America;
 Affidavit of Mr. Benjamin W. Griffiths, Energy Analyst,
- Attachment N-1e: Massachusetts Attorney General's Office, with the memorandum entitled "Revenue for Energy Storage Participating in ISO-NE Energy and Reserves Markets" (Griffiths Memorandum), affixed as Appendix A to that Affidavit;
- Attachment N-11: Testimony of Ms. Sarah Bresolin Silver, Director of Government and Regulatory Affairs, ENGIE North America Inc.;
- Attachment N-1g: Summary of the NEPOOL Participant Processes;
- Attachment N-1h: March 24, 2021 NEPOOL Participants Committee Vote Tabulation;
- Attachment N-1i: Blacklined Tariff sheets containing NEPOOL's proposed revisions to the Tariff to become effective June 8, 2021; and

³ See March 24, 2021 NEPOOL Participants Committee Vote Tabulation, <u>Attachment N-1h</u>.

⁴ NEPOOL Participants register their individual positions by voting on NEPOOL matters and, if they wish, through further explanations of their views during the stakeholder process. NEPOOL's positions are defined by the voting results. The affidavit/testimonies reflect the views of the testifying individuals' respective companies, entities, or agencies, and do not reflect in all instances the positions or opinions of all NEPOOL Participants.

• Attachment N-1j: Clean Tariff sheets containing NEPOOL's proposed revisions to the Tariff to become effective June 8, 2021.

I. SNAPSHOT SUMMARY OF THE COMPETING ORTP VALUES

This joint Section 205 "jump ball" filing offers for the Commission's consideration two competing ORTP proposals: the ISO ORTP Proposal⁵ and the NEPOOL Alternative. The following table shows the proposed technology-specific ORTPs, identifying in green highlight where the NEPOOL values differ from the ISO-proposed values.

Table 1 Proposed ORTPs				
Generating Capacity Resources				
Technology Type	ISO-NE (\$/kW-month)	NEPOOL (\$/kW-month)		
Simple Cycle Combustion Turbine	\$5.355	\$5.355		
Combined Cycle Gas Turbine	\$9.811	\$9.811		
On-Shore Wind	\$0.000	\$0.000		
Off-Shore Wind	FCA Starting Price	\$0.000		
Energy Storage Device – Lithium Ion Battery	\$2.912	\$2.601		
Photovoltaic Solar	\$1.381	\$0.000		
Demand Capacity Resources				
Technology Type	ISO-NE and NEPOOL (\$/kW-month)			
Load Management (Commercial / Industrial)	\$0.750			
Previously Installed Distributed Generation	\$0.750			
New Distributed Generation	Based on generation technology type			
On-Peak Solar	\$5.414			
Energy Efficiency	\$0.000			

II. JUMP BALL STANDARD

The Commission-approved governance documents, which include the Participants Agreement, provide the contractual arrangements under which ISO-NE fulfills the role of New England's regional transmission organization. Under Section 11.1.5 of the Participants Agreement—the "jump ball" provisions—ISO-NE is required to submit a jump ball filing when NEPOOL supports, by at least a 60% Vote, Market Rule changes that are different than ISO-NE proposed changes. In a jump ball filing, the NEPOOL alternative changes, which are filed under Section 205 of the Federal Power Act (FPA), are treated on the same legal footing as the ISO's proposal. Rather than the Commission being limited to a more passive role typically associated

⁵ In its transmittal letter and associated supporting materials, the ISO presents a more fulsome explanation of its ORTP proposal.

with Section 205 filings,⁶ the jump ball provisions provide the Commission the latitude to "*adopt any or all* of [ISO-NE's] Market Rule proposal *or* the alternate [NEPOOL] Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable."⁷

Here, the NEPOOL-supported modifications are material to the ORTP provisions and, absent the jump ball, the Commission could be limited to rejecting the ISO ORTP Proposal rather than accepting/ordering preferable revisions.⁸ The jump ball, therefore, permits the Commission to select any or all of the NEPOOL-approved changes to the ISO's proposal that it finds preferable, without being required first to reach a determination that ISO-NE proposal is unlawful.

III. COMMUNICATIONS AND CORRESPONDENCE

Communications and correspondence regarding this proceeding should be sent to the following individuals:

Dave Cavanaugh Chair, NEPOOL Participants Committee 5 Hampshire Street, Suite 100 Mansfield, MA 02048 413.896.6757 dcavanaugh@ene.org David T. Doot Sebastian M. Lombardi Rosendo Garza, Jr. Day Pitney LLP 242 Trumbull Street Hartford, Connecticut 06103 860.275.0663 <u>dtdoot@daypitney.com</u> <u>slombardi@daypitney.com</u> rgarza@daypitney.com

⁶ In typical Section 205 proceedings, the Commission "plays 'an essentially passive and reactive' role," allowing it to "reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable." *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 9, 10 (D.C. Cir. 2002). Therefore, the Commission's inquiry is circumscribed "into whether the rates proposed by a utility are reasonable – and not to extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs." *Cities of Bethany et al. v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984). The filed proposal "need not be the only reasonable methodology, or even the most accurate." *OXY USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995). As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept a proposal reflected in this Section 205 filing if the Commission concludes the proposal is just and reasonable. *S. Cal. Edison Co.*, 73 FERC ¶ 61,219 at 61,608 n.73 (1995) (citation omitted).

⁷ Participants Agreement § 11.1.5 (emphases added).

⁸ See NRG Power Mktg., LLC v. Fed. Energy Regul. Comm'n, 862 F.3d 108, 110 (D.C. Cir. 2017) ("Section 205 does not allow FERC to make modifications to a proposal that transform the proposal into an entirely new rate of FERC's own making.").

IV. RELEVANT BACKGROUND

New England's Minimum Offer Price Rule (MOPR) subjects all new entrants to a minimum offer price—the ORTP—which is an administratively determined default minimum price for new capacity resource offers into the Forward Capacity Auction (FCA). ORTPs are intended to serve as screens designed to help ensure uneconomically low-priced offers do not enter into an FCA.⁹ In effect, ORTPs establish a rebuttable presumption that offers below the ORTP threshold may be the product of buyer-side market power and, therefore, are neither just nor reasonable. Through the unit-specific offer review process, the burden rests on the offeror to justify a lower-than-ORTP value to the satisfaction of the ISO's Internal Market Monitor (IMM).

The Tariff requires the ISO to recalculate values for certain FCM parameters, including ORTPs, on at least a triennial basis, using updated data.¹⁰ In this instant proceeding, ISO-NE and NEPOOL submit alternative sets of proposed ORTP values, as well as other related Tariff revisions. The ISO proposes to use revised ORTPs in FCA 16, to be held in February 2022, for the Capacity Commitment Period (CCP) June 2025–May 2026, as well as in FCAs 17 and 18 to be held in 2023 and 2024, respectively. To assist in its recalculation of proposed ORTPs, ISO-NE engaged Concentric Energy Advisors, Inc. (CEA), who in turn subcontracted with Mott MacDonald (MM).¹¹

A. The Tariff requires ISO-NE to establish technology-specific ORTPs, which serve as benchmarks to screen out offer prices that plainly appear commercially implausible absent out-of-market revenues.

To develop proposed ORTPs, the ISO begins by selecting technology types based on certain vetting criteria.¹² During this process to calculate ORTPs for those technology types, the ISO attempts to spread the total investment costs for the selected resources over those resource's estimated useful life.¹³ In so doing (and as required by Tariff Section III.A.21.1.2(b)), the ISO

⁹ See ISO New England Inc., 142 FERC ¶ 61,107 at P 38 (2013). The ORTP reflects the FCM revenue each resource type needs for a new project to be commercially plausible based on forecasted project costs and non-capacity revenues from the ISO markets, as well as other competitive sources, such as state Renewable Energy Certificates and the federal Investment Tax Credit.

¹⁰ Tariff §§ III.13.2.4, III.A.21.1.2(a). Note, however, that this triennial review has already been delayed by one year. *See Letter Order re: Consolidation of Forward Capacity Market Parameter Review*, Docket No. ER19-335-000 (issued Dec. 19, 2018) (accepting joint request to delay the recalculation).

¹¹ Concentric Energy Advisors, Inc. and Mott MacDonald, *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*, Docket No. ER21-787-000, at 8 (Dec. 2020) (CEA Dec. Report); *see also* Concentric Energy Advisors, Inc. and Mott MacDonald, *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 Addendum March 2021*, Docket No. ER21-787-001, at 1 (filed Mar. 2021).

¹² CEA Dec. Report at 8, 14–16.

¹³ *ISO New England Inc.*, 142 FERC ¶ 61,107 at P 64 (2013).

employs a real levelization method, which uses a capital budgeting model¹⁴ that is employed to determine the break-even contribution from the FCM to yield a discounted cash flow with a net present value of zero for a particular technology type.¹⁵ Since its inception in early 2013, rather than specifically estimating the useful life for the selected technology types, the ISO's capital budgeting model has limited all new generating capacity resources' economic lives to twenty years when calculating the technology-specific ORTPs, no matter the technology type.¹⁶

As part of the process to calculate technology-specific ORTPs, certain assumptions (as the Tariff requires) are input into the capital budgeting model, namely, "expected non-capacity revenues and operating costs" (including assumptions regarding taxes).¹⁷ Additionally, although not required by the Tariff, the ISO has employed what it calls a "bottom-up" cost analysis to estimate capital costs when calculating ORTPs.¹⁸ The ISO has explained that its use of the "bottom-up" approach provides the opportunity to cross-compare the expected cost components against other publicly available datasets for reasonableness, as the IMM suggests it has done in the past.¹⁹

Although ORTPs are meant to be a screen to evaluate the competitiveness of new resources offering into the FCA, the ISO has importantly acknowledged that ORTPs should be "set at a level consistent with expected prevailing market conditions"²⁰ and at "the low end of the spectrum of estimated costs"²¹ to ensure effective implementation of buyer-side mitigation.²² When done correctly, ORTPs are not only set at "the low end of the spectrum of estimated costs,"²³ but also serve as the tool to review *only* those "offers that plainly appear commercially implausible absent out-of-market revenues."²⁴

¹⁴ Inputs into the capital budgeting model include a new capacity resource's capital costs, revenues, and assumptions regarding depreciation, taxes, and discount rate. *See* Tariff § III.A.21.1.2(b).

¹⁵ *Id.*

¹⁶ See Tariff § III.A.21.1.2(b); CEA Dec. Report at 80.

¹⁷ Tariff § III.A.21.1.2(b).

¹⁸ This analysis, which is not codified in the Tariff, defines "the individual components of a project (i.e., equipment costs, labor costs, engineering costs, interconnection fees, etc.), estimating each of the project's component costs and, finally, summing the individual component costs to develop a total project cost." ISO New England Inc., Revisions to Forward Capacity Market Offer Review Trigger Price Provisions, Joint Testimony of David Naughton and Scott Hodgson, Docket No. ER14-616-000, at 14:3–6 (filed Dec. 13, 2013).

¹⁹ See id. at 15:4–5.

²⁰ ISO New England Inc., Revisions to Forward Capacity Market Offer Review Trigger Price Provisions, Docket No. ER14-616-000, at 6 (filed Dec. 13, 2013) (ISO Dec. 2013 Filing).

²¹ ISO New England Inc., Filing of CONE and ORTP Updates, Docket No. ER17-795-000, at 13 (filed Jan. 13, 2017) (citing 142 FERC ¶ 61,107 at P 38) (ISO Jan. 2017 Filing).

²² ISO Dec. 2013 Filing at 6.

²³ ISO Jan. 2017 Filing at 13 (citation omitted).

²⁴ 142 FERC ¶ 61,107 at P 38. Of note, under New England's current FCM rules, if a particular technology type's ORTP is calculated to be lower than the FCA's starting price, then a technology-

B. A new capacity resource's offer price that is below the technology-specific ORTP is subject to the IMM's unit-specific offer mitigation review process.

During the qualification process, a new capacity resource seeking to submit an offer price below the relevant ORTP during the FCA must undergo a unit-specific offer review that is conducted by the IMM.²⁵ As part of this review, the Tariff imposes a burden on the new capacity resource to overcome the presumption that the offer "plainly appear[s] commercially implausible absent out-of-market revenues"²⁶ and that it would be unjustified to allow the offer to enter into the FCA. Specifically, the new capacity resource's Project Sponsor must submit certain documentation to justify its offer below the relevant ORTP.²⁷ Absent a demonstration to the discretionary satisfaction of the IMM, the IMM will mitigate the offer up to the relevant ORTP.²⁸

Tariff Section III.A.21.2(b) establishes the method the IMM uses to evaluate an offer price below the relevant ORTP. Using a similar capital budgeting model²⁹ that was used to develop the benchmark ORTPs, the IMM enters the information/data provided by the Project Sponsor regarding the new capacity resource's relevant costs and its assumptions concerning market revenues, excluding what it considers out-of-market revenues.³⁰ The IMM also reviews depreciation, taxes, and the discount rate "to ensure that it is consistent with overall market conditions."³¹ Importantly, the IMM can override a Project Sponsor's assumptions with its own if the IMM, in its discretion, believes the assumptions are inconsistent with prevailing market conditions.³² Ultimately, the model is intended to establish the break-even contribution required from the FCM to yield a discounted cash flow with a net present value of zero for the specific unit.³³ To assist Market Participants in meeting their burden of demonstrating that their offers

 25 See Tariff § III.A.21.1. The opposite is also true. If the offer price is equal to or above the relevant ORTP, then the resource's offer price is not reviewed.

²⁶ 142 FERC ¶ 61,107 at P 38.

²⁷ See Tariff § III.A.21.2(b)(iv) (describing the various documentation that must be submitted to justify an offer price below the relevant ORTP).

²⁸ Tariff § III.A.21.2(b)(iv) ("If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.").

²⁹ Note that this Tariff provision does not explicitly require that the capital budgeting model be fixed at twenty years. *See* Tariff § III.A.21.2(b).

³⁰ Tariff § III.A.21.2(b)(i).

³¹ *Id*.

³² *See id.*

³³ Tariff § III.A.21.2(b).

specific ORTP is included in the Tariff. But, if a technology type's ORTP is higher than the FCA Starting Price, then that technology type will not be included in the Tariff. Rather, its default ORTP is the starting price. *See* Tariff § III.A.21.1.1 (showing that "[a]ll other technology types" of resource will be set at the FCA Starting Price).

are satisfactory to the IMM, Section III.A.21.2(b)(iv) describes the type of documentation a new resource must provide to the IMM.

V. OVERVIEW OF THE NEPOOL STAKEHOLDER PROCESS TO UPDATE AND CONSIDER ORTPS FOR FCA 16

NEPOOL's stakeholder process is critical to developing improvements to, and solutions for, the region's markets. As the primary means for Participants, State officials, and ISO-NE to review and discuss changes to the Tariff, the NEPOOL process provides the regional forum for informed stakeholder feedback and advisory input on any proposed changes to the ISO-NE Tariff. Within these processes regional stakeholders are afforded fulsome opportunities to discuss, understand, clarify, and work together to narrow and/or resolve issues of controversy and—when consensus cannot be achieved on an ISO-NE proposal—to identify and advocate for alternative solutions.

In this case, the protracted NEPOOL stakeholder process to review and consider proposed updated ORTPs for FCA 16 resulted in NEPOOL approving an alternate set of ORTPs to that of ISO-NE. The NEPOOL process that led to the NEPOOL Alternative took place over the course of nearly a year. Starting in May 2020, the ISO began presenting its proposal to the NEPOOL Markets Committee. In addition to ORTPs, NEPOOL concurrently reviewed the ISO's proposed recalculation of the Cost of New Entry (CONE), Net CONE, and Performance Payment Rate (PPR) values, as well as changes to the methodology to calculate the Dynamic De-List Bid Threshold (DDBT)³⁴ in the FCM.³⁵

³⁴ The modified approach to calculating the DDBT was voted separately and submitted to the Commission as a joint ISO/NEPOOL proposal on December 31, 2020. ISO New England Inc. and New England Power Pool, Market Rule 1 Change to Implement New Methodology for Calculating Forward Capacity Market Dynamic De-List Bid Threshold, Docket No. ER21-782-000 (filed Dec. 31, 2020). This Commission-approved DDBT filing was a testament to the effectiveness of New England's Participant Processes, producing a solution that converted an ISO-NE initial proposal that failed to garner enough support from NEPOOL to a joint proposal (which was co-sponsored by generators and the New England States Committee on Electricity) that enjoyed near unanimous support of NEPOOL. *See ISO New England Inc. and New England Power Pool Participants Committee*, 174 FERC ¶ 61,162 (2021).

³⁵ A complete package of ISO-proposed FCM parameters, i.e., CONE, Net CONE, PPR, and ORTPs, were considered through the complete NEPOOL Participant Processes. At its December 3, 2020 meeting, the NEPOOL Participants Committee approved a package of Tariff revisions for CONE, Net CONE, PPR, and ORTP values. Only the ORTPs differed from those of the ISO. As the ISO explained in its earlier filing, the CONE, Net CONE, and PPR updates were bifurcated from the ORTPs; thus, those updates are the subject of a separate Section 205 filing. *See* ISO New England Inc., Updates to CONE, Net CONE, and Capacity Performance Payment Rate, Docket No. ER21-787-000 (filed Dec. 31, 2020) (ISO Dec. 31 Filing). Later, the Commission issued a deficiency letter requesting additional information. *ISO New England Inc.*, Updates to CONE, Net CONE, and Capacity Performance Payment Rate, Docket No. ER21-787-000 (issued Mar. 1, 2021). Recently, the ISO filed its response where, *inter alia*, it updated the CONE, Net CONE, and PPR values. ISO New England Inc., Response to Commission Deficiency Notice and Revised CONE, Net CONE, and Capacity Performance Payment Rate, Docket No. ER21-787-001, at 4 (filed Mar. 30, 2021).

Turning to the technology-specific ORTPs, the ISO's proposed values were considered through the entire NEPOOL stakeholder process and were subjected to additional vetting after initial completion of the process in December 2020. Although NEPOOL approved an alternative set of ORTPs at its December 3, 2020 Participants Committee meeting,³⁶ the NEPOOL process was re-opened earlier this year after a material change in federal tax law. After the December 3 NEPOOL vote, the United States Congress passed the Consolidated Appropriations Act, 2021 (the Act), which was signed into law on December 27, 2020.³⁷ The Act, among other things, extended the beginning of construction deadline for the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) for certain renewable resources,³⁸ which affected the ORTP calculations for those resources. As a result, the ISO recalculated the impacted ORTPs. Further, as a result of the stakeholder process and upon discovery of certain errors in the work of its consultants, the ISO adjusted and modified its earlier proposal, which resulted in additional revisions to some of the ORTP provisions.³⁹ In the end, with a 19.04% Vote in favor, NEPOOL did not support the ISO ORTP Proposal but, with a 72.50% Vote in favor, approved its own alternative.⁴⁰

VI. THE NEPOOL ALTERNATIVE IS "JUST AND REASONABLE AND PREFERABLE" TO THE ISO PROPOSAL

Pursuant to its authority and discretion, the Commission may consider the separate components of the NEPOOL Alternative and approve the components it finds preferable to the corresponding one in the ISO ORTP Proposal. The NEPOOL Alternative proposes more accurate and reasonable ORTPs, which are based on the Commission's previously approved standard that ORTPs should be set at expected prevailing market conditions.⁴¹ The NEPOOL-supported changes ensure new capacity resources, particularly renewable and storage resources, are not unfairly disadvantaged by being subjected to inflated ORTPs. In short, the NEPOOL Alternative offers the Commission several changes to ORTP values and related Tariff provisions that individually and collectively are "just and reasonable and preferable" to the ISO ORTP Proposal.

³⁶ See Minutes of the NEPOOL Participants Committee Meeting, at 4360 (Dec. 3, 2020), <u>https://nepool.com/wp-content/uploads/2021/01/Minutes_NPC_2020_1203.pdf</u> (providing that the Participants Committee approved, *inter alia*, an alternative set of ORTPs, with a 71.84% Vote in favor).

³⁷ Consolidated Appropriations Act, 2021, Pub. L. No. 116-260, 134 Stat. 1182.

³⁸ Consolidated Appropriations Act, 2021, Pub. L. No. 116-260, Div. EE, § 132, 134 Stat. 1182.

³⁹ See Memorandum of ISO New England to NEPOOL Markets Comm., subject: Revisions to the Offer Review Trigger Price for Solar Resources for FCA 16, at 1 (Mar. 10, 2021), <u>https://www.iso-ne.com/static-assets/documents/2021/03/a0 iso memo revisions solar ortp fca 16 and summary iso responses ortp amendments.pdf</u>.

⁴⁰ A more complete explanation of the stakeholder process is presented in <u>Attachment N-1g</u>.

⁴¹ *E.g., ISO New England Inc.*, 146 FERC ¶ 61,084 at PP 6, 18, 39 (2014) (accepting ORTPs for certain technology types that the ISO set "at a level consistent with expected prevailing market conditions," e.g., combustion turbines, but not others, e.g., offshore wind, based on then existing lack of cost information).

As the Commission weighs the merits of the NEPOOL Alternative and the ISO ORTP Proposal, NEPOOL urges the Commission to fully consider the broad stakeholder support achieved for NEPOOL's preferred proposal consistent with the long-standing view that "stakeholder consensus is an *important factor* to be considered in reviewing the just[ness] and reasonableness of a rate design."⁴²

In summary, the components of the NEPOOL Alternative are as follows:

- A. <u>The Economic Life Proposal</u>: NEPOOL proposes a new definition that would allow for a more accurate determination of a resource's economic life, consistent with industry practice, and would remove the Tariff's current over-simplified and unrealistic limitation of a twenty-year economic life for all generation technology types, including wind and solar resources. As a result of NEPOOL's Economic Life Proposal, the NEPOOL Alternative includes a slightly lower solar ORTP than the ISO's.
- B. <u>NEPOOL's Unit-Specific Offer Review Proposal</u>: This proposal adds Tariff language that would assist Market Participants in meeting their burden during the unit-specific offer review process by including non-exhaustive lists of the types of documentation a Project Sponsor can provide to the IMM to justify an economic life beyond twenty years and to determine the weighted average cost of capital (WACC) when excluding out-of-market revenues.
- C. <u>NEPOOL's Offshore Wind ORTP Value of \$0.000/kW-month</u>: This NEPOOL-approved ORTP is reasonable and preferable to the ISO's overly inflated ORTP for offshore wind. Referred to as the "Offshore Wind ORTP Proposal," NEPOOL's preferred proposal appropriately takes into account a more reasonable economic life of offshore wind resources and their decreasing capital costs.
- D. <u>The PTC/ITC Proposal</u>: NEPOOL's proposal adds Tariff language to require the ISO, during the intervening years when ORTPs are adjusted, to use certain ITC percentages for solar resources and, if the federal tax law changes, to update the tax credit inputs for all resources with the most current federal tax law.
- E. <u>NEPOOL's Lower Battery ORTP Value</u>: The NEPOOL Alternative offers a slightly lower—but more accurate—ORTP value for the Energy Storage Device Lithium Ion Battery technology type, which is consistent with how a battery storage resource operates in the wholesale markets.
- F. <u>NEPOOL-approved Clarifications to the Current Weighted Average Formula Tariff</u> <u>Provisions</u>: Referred to as the "Combined Resources ORTP Proposal," this NEPOOL proposal offers a just and reasonable approach to ensure that the currently-effective weighted average formula is applied (as intended by the Tariff) to a New Capacity

⁴² *ISO New England Inc.*, 132 FERC ¶ 61,122 at P 22 (2010) (emphasis added; citation and internal quotation marks omitted), *order on clarification*, 135 FERC ¶ 61,029 (2011), *order on reh'g, clarification, and compliance filing*, 138 FERC ¶ 61,027 (2012).
Resource comprised of one or more Assets that share a common point of interconnection (POI) and participate in the FCM as a single capacity resource. Also, this proposal clarifies how the ORTP for two Assets behind the same POI, which participate in the FCM separately as two distinct New Capacity Resources, shall be calculated.

A. NEPOOL's Economic Life Proposal

As widely reported, technological advancements have extended the economic life of certain resources well beyond twenty years.⁴³ Because the current Tariff's inflexible twenty-year limit⁴⁴ (which has remained unchanged since 2013) does not make an allowance for this reality, it does not reflect the advancements in these technologies for certain resources. Specifically, employing the current Tariff provision in its capital budgeting model limits all generation technologies to twenty years' worth of costs and revenues, thereby excluding costs and revenues beyond the first two decades of operation. The consequence of the ISO's outdated practice is an overstatement of certain resources' FCM revenue requirements when calculating the technology-specific ORTPs. In doing so, the ISO inflates certain ORTPs.⁴⁵ Continued reliance on a standardized economic life assumption can result in unjustifiably high ORTPs (particularly for renewable technology types), and it could make it impossible for developers of those new resources to support their offers and potentially to acquire and be paid for a Capacity Supply Obligation.

⁴³ See, e.g., Attachment N-1b, Testimony of Ms. Abigail Krich at 10:11–14 (providing that a Lawrence Berkley National Laboratory report "demonstrates that wind professionals currently anticipate project lifetimes far longer than the ISO's standard 20-year economic life assumption") (Krich Test.); id. at 13:11-14 (explaining that "solar industry professionals" have opined that they anticipate lifetimes for solar projects with greater than twenty years and many anticipating lifetimes greater than thirty years); see also id. at 11:1-3 (showing, in Figure 1, the "[c]urrent [u]seful-[l]ife for [w]ind [p]lants"); id. at 13:16-14:3 (depicting, in Figure 1, the "[c]urrent [p]roject [l]ife [e]xpectations for [u]tility-[s]cale PV"). See also Ryan H. Wiser et al., Benchmarking Utility-Scale PV Operational Expenses and Project Lifetimes: Results from a Survey of U.S. Solar Industry Professionals, Lawrence Berkeley National Lab. (June 2020), https://eta-publications.lbl.gov/sites/default/files/solar_life_and_opex_report.pdf; Ryan Wiser & Mark Bolinger, Benchmarking Anticipated Wind Project Lifetimes: Results from a Survey of U.S. Wind Industry Professionals, Lawrence Berkeley Nat'l Lab. (Sept. 2019), https://etapublications.lbl.gov/sites/default/files/wind useful life report.pdf.

⁴⁴ Tariff § III.A.21.1.2. This economic life limitation was set, in part, due to the fuel costs of gas fired power plants, but such considerations do not hold the same relevance for wind and solar resources which have no fuel costs—making a twenty year economic life "arbitrary and illogical." *See Calpine Corp. et al.*, 171 FERC ¶ 61,034 at P 86 n.495 (2020) (noting that it is "arbitrary and illogical' to mandate that resources assume a 20-year asset life when most renewable units typical have a useful commercial life of 35 years") (Glick, C. dissenting).

⁴⁵ *Compare* Krich Test. at 8:8–10 (stating that "[u]nnecessarily shortening the assumed economic life of [solar and offshore wind] resources in calculating ORTPs inappropriately raises the values of their ORTPs") *with id.* at 16:16–17 (explaining that, "[b]y extending the economic life for wind and solar facilities, the ORTP for these resources decreases").

i. Description of the Economic Life Proposal.

NEPOOL supports an alternative approach for determining the appropriate economic life when calculating ORTPs. First, NEPOOL's Economic Life Proposal provides a new definition that would allow a resource's economic life to be as long as thirty five years. Specifically, this proposal introduces a new defined Tariff term, "New Capacity Resource Economic Life," as follows:

[T]he number of years that is the lesser of (a) the period of time that a New Capacity Resource of a given technology type or types would reasonably be expected to operate before the resource becomes unprofitable for at least two consecutive years, (b) the expected physical operating life of the resource, or (c) 35 years.⁴⁶

Second, in concert with this new proposed term, the NEPOOL Alternative removes the Tariff's current over-simplified and outdated limitation of economic life for all types of generating resources to twenty years. NEPOOL proposes to replace the relevant Tariff language that limits the capital budgeting model to twenty years with language that allows the model to consider the New Capacity Resource Economic Life appropriate to each technology.⁴⁷

As a result of not excluding costs and revenues beyond twenty years for solar and wind resources technology types, the NEPOOL Alternative offers an ORTP value for solar that differs from the ISO's proposal. Under prevailing market conditions, "solar professionals currently anticipate project lifetimes far longer than the ISO's standard assumption."⁴⁸ Indeed, within the solar industry it is reported that some anticipate a solar project's lifetime could be as high as thirty-five years.⁴⁹ The sponsors of the NEPOOL Alternative, however, relied on a more conservative economic life of thirty years for solar.⁵⁰ Assuming this economic life for a solar project decreases its calculated ORTP to \$(6.491)/kW-month, which resulted in NEPOOL's approved \$0.000/kW-month ORTP for solar.⁵¹

ii. NEPOOL's Economic Life Proposal ensures economic lives for resources that are more consistent with industry expectations and prevailing market conditions.

The Economic Life Proposal is a just and reasonable solution that ensures the ORTPs are set at reasonably accurate levels consistent with expected prevailing market conditions. First, the

⁴⁸ *Id.* at 13:10–11.

⁴⁶ See <u>Attachment N-1i</u>, NEPOOL Marked Tariff § I.2.2 (NEPOOL Marked Tariff).

⁴⁷ *Id.* § III.A.21.1.2(b). As explained in the Krich Testimony, for FCA 16, the New Capacity Resource Economic Life used in the calculation of the NEPOOL-supported ORTPs for onshore and offshore wind resources would be twenty-five years, for solar resources would be thirty years, and for all other generating technology types would remain twenty years. *See* Krich Test. at 10:7–9, 15:4–7.

⁴⁹ *Id.* at 13:11–14.

⁵⁰ *See id.* at 15:5–7.

⁵¹ *Id.* at 17:14–17.

proposed term ("New Capacity Resource Economic Life") offers a rational approach to define a new resource's economic life, consistent with how a rational owner will operate such a resource.⁵² Second, the new definition ensures that, when calculating ORTPs, the ISO will account for the full amount of costs and revenues that are tied to the economic life of a resource, reflecting the reality of technology advancements, which makes the Economic Life Proposal preferable to the ISO's approach.⁵³ The ISO, by contrast, maintains the outdated *status quo* in spite of the proffered evidence that certain resources, under prevailing market conditions, have economic lives that extend well beyond twenty years.⁵⁴ In short, NEPOOL's Economic Life Proposal is more consistent with industry practice and expectations—as well as the reality of the markets—than the ISO's treatment of economic life, and is, therefore, just and reasonable and preferable.

B. NEPOOL's recommendation to enhance the Tariff's unit-specific offer review provisions is preferable to the inherent ambiguity of the current applicable Tariff provisions.

The current Tariff (which the ISO ORTP Proposal does not amend or clarify) is ambiguous in three important respects: (1) whether a new capacity resource could claim and justify (through appropriate documentation) an economic life, i.e., beyond twenty years, that is different than what is assumed in the ORTP calculation; (2) whether the IMM would consider and review any documentation to support this claim; and (3) what type of documentation a resource must submit to determine its WACC if it receives out-of-market revenues. These uncertainties exacerbate challenges for market participation in the FCM.

Although the unit-specific offer review provisions of the current ISO-NE Tariff do not explicitly prohibit a new capacity resource from proposing an economic life beyond twenty years,⁵⁵ legitimate concerns remain given the ISO's refusal to recognize a longer-than twenty-year economic life for newer and evolving technologies in the FCM. Further, these concerns, which were expressed by affected Market Participants in the stakeholder process, have not been assuaged by the current Tariff language, or by the IMM, both of which have offered little (if any) guidance or clarity on the matter.

In fact, based on "direct experiences" from two such Participants (Enel X and Borrego), "the IMM has read the Tariff in a way that unreasonably restricts its review and acceptance of

⁵² See id. at 9:1–2 ("A rational capacity resource owner will continue to operate its asset until it becomes consistently economically unprofitable.").

⁵³ See generally id. at 15:10–12 (providing that, by "[a]dding this definition [of "New Capacity Resource Economic Life," it] will ensure the ISO more fully captures the expected costs and revenues of wind and solar projects over their projected lifetimes and reflects the full economic value of the resources").

⁵⁴ *E.g.*, *id.* at 10:5–6 (explaining that "researchers and industry professionals have been using at least 25 years to model wind facilities . . . (if not longer)").

⁵⁵ Tariff § III.A.21.2(b) (stating that the IMM "shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate in the capital budgeting model" without limiting the model to twenty years).

bids that are based on the actual economic lives" of resources.⁵⁶ During the most recent FCA 15 qualification process, representatives from Enel X and Borrego observed that their resources' economic lives was "limited to the twenty-year standardized economic life."⁵⁷ The apparent position of the IMM on this issue⁵⁸ coupled with the existing Tariff's ambiguity as to the type of additional documentation a resource could provide to justify an economic life beyond twenty years prompted certain NEPOOL members to propose adding clarifying language to the Tariff (as reflected in the NEPOOL Alternative).⁵⁹

To address the issues borne out of the ambiguity in the current Tariff, the NEPOOL Alternative provides a reasonable and preferable solution. First, it proposes Tariff language to clarify that a new capacity resource (during the unit-specific offer review process) has the ability to claim (and justify) an economic life beyond twenty years.⁶⁰ To that end, NEPOOL's Unit-Specific Offer Review Proposal includes NEPOOL's newly defined "New Capacity Resource Economic Life"⁶¹ as one of the assumptions to be used in the capital budgeting model.⁶² The proposal expressly requires that the Project Sponsor bears the burden of justifying an economic life beyond what is assumed in the ORTP calculation, and must provide sufficient documentation to support the claimed economic life.⁶³

Without NEPOOL's clarifying language, especially in the context of the explicit twenty year limitation in currently effective Section III.A.21.2, new capacity resources run substantial risk that they will be unable to demonstrate an economic life beyond what is assumed in the ORTP calculation during the unit-specific offer review process to the discretionary satisfaction of the IMM. Exacerbating this issue is the IMM's perceived stance that, during the unit-specific

⁵⁶ <u>Attachment N-1d</u>, Joint Testimony of Ms. Elizabeth Delaney and Dr. Michael Macrae at 6:6–8 (Delaney/Macrae Joint Test.).

⁵⁷ Delaney/Macrae Joint Test. at 10:18.

⁵⁸ *Id.* at 11:5–7 (stating that "the IMM has not indicated during that process (not in the NEPOOL stakeholder process) whether they have the authority to permit usage of an economic life exceeding the twenty-year default").

⁵⁹ *Id.* at 10:19–11:2 ("[T]he current ISO-NE Tariff neither specifies how the IMM should assess economic life, nor clarifies the documentation a Project Sponsor needs to submit in support of their economic life assumptions.").

⁶⁰ See id. at 7:19 n.1; see also id. at 9:22–10:1 (explaining that "[c]hanges in the energy industry have disrupted typical market assumptions, including an outdated expectation that a generation resource's economic life would not exceed twenty years").

⁶¹ This term is also part of the Economic Life Proposal. *See* Section VI.A. If the Commission were to reject the Economic Life Proposal but accept the Unit-Specific Offer Review Proposal, then the new defined term "New Capacity Resource Economic Life" would necessarily be part of the Unit-Specific Offer Review Proposal.

⁶² NEPOOL Marked Tariff § III.A.21.2(b). *See also* Delaney/Macrae Joint Test. at 7:14–19.

⁶³ NEPOOL Marked Tariff § III.A.21.2(b).

offer review, only twenty years of cash flows can be evaluated in the capital budgeting model.⁶⁴ Indeed, neither Enel X nor Borrego are "aware of the IMM using an economic life beyond twenty years"⁶⁵ during the unit-specific offer review process. Enel X and Borrego's "direct experiences with the unit-specific offer review process have shown that the IMM has read the Tariff in a way that unreasonably restricts its review and acceptance of bids that are based on the actual economic lives of the resources."⁶⁶

Separately, the current Tariff offers no suggestion on what documentation a Project Sponsor can provide during the unit-specific review process to determine the appropriate WACC assumption if the project is receiving out-of-market revenues.⁶⁷ And, "the IMM has indicated that the existing Tariff requires them to use a different [WACC] . . . than the actual WACC for a resource that receives what it views as out-of-market revenues."⁶⁸ As such, the Unit-Specific Offer Review Proposal also makes two revisions to Section III.A.21.2(b)(iv).

First, the NEPOOL Alternative adds Tariff language identifying a non-exhaustive list of documents to justify an economic life beyond what is assumed in the ORTP calculation⁶⁹ that is largely borrowed from similar language that was recently approved by the Commission in a PJM Interconnection LLC (PJM) proceeding.⁷⁰ Second, the NEPOOL-supported proposal includes Tariff language clarifying the documentation a Project Sponsor can provide in determining a suitable proxy WACC for a new resource if the IMM determines the project's actual WACC is dependent on out-of-market revenue and, therefore, unable to be used in their unit-specific review analysis. This hypothetical WACC is deemed necessary by the IMM to determine the impact of out-of-market revenues and to exclude them during the unit-specific offer review process.⁷¹ These lists not only put new capacity resources on notice of what is required to justify a claim of an economic life beyond what is used in the ORTP calculation or what types of

⁶⁴ Delaney/Macrae Joint Test. at 6:5–9; 11:4–7. For instance, "[b]ased on [Enel X and Borrego's] experience, the IMM has not provided clarity in its application of currently effective Tariff language." *Id.* at 6:14–15.

⁶⁵ *Id.* at 11:4–5.

⁶⁶ *Id.* at 6:5–8.

⁶⁷ Tariff § III.A.21.2(b)(iv) (providing a thorough explanation and abundant examples of the types of documentation and information to justify a resource's costs and revenues but providing no such explanation or examples for a new capacity resource to justify determine its WACC).

⁶⁸ Delaney/Macrae Joint Test. at 6:9–12.

⁶⁹ NEPOOL Clean Tariff § III.A.21.2(b)(iv).

⁷⁰ Calpine Corp. et al. v. PJM Interconnection, L.L.C., 173 FERC ¶ 61,061 at P 281 (2020).

⁷¹ See NEPOOL Marked Tariff § III.A.21.2(b)(iv). The Unit-Specific Offer Review Proposal does not impact any ORTP included in either the NEPOOL Alternative or the ISO ORTP Proposal. The effects of this proposal would only come to fruition during the qualification process when a new capacity resource submits an offer floor price lower than the relevant ORTP as part of its new capacity qualification package.

documents can be used to exclude out-of-market revenues from the WACC assumption,⁷² but also provide the IMM with assistance with the unit-specific offer review process.

C. NEPOOL's proposed value for the Offshore Wind ORTP is more accurately aligned with prevailing market conditions.

Relying on assumptions about the capital costs of offshore wind that are *not* consistent with prevailing market conditions, the ISO ORTP Proposal offers no ORTP for offshore wind because using such assumptions resulted a calculated value above the FCA Starting Price. Based on a purported bottom-up cost analysis performed by the ISO's consultants with the use of "proprietary" information, the ISO's assumed overnight capital cost to construct an offshore wind project in New England is \$5,358/kW (2019\$). As explained in the Krich Testimony and shown in the Gilbert Testimony, this assumed capital cost is materially higher than expected prevailing market conditions.⁷³ Using this cost—coupled with an assumed twenty-year economic life—predictably produces an outdated and unrealistic ORTP for offshore wind.⁷⁴

The NEPOOL Alternative includes an ORTP of \$0.000/kW-month for offshore wind. This value was calculated by using a twenty-five-year economic life for offshore wind and applying an assumed capital cost of \$3,326/kW (2019\$), which as supported by testimony included with this filing reasonably and more closely reflects prevailing market conditions than ISO's proposal.

i. Under today's prevailing market conditions, an appropriate economic life for offshore wind projects is (conservatively) twenty-five years.

Technological advancements have allowed offshore wind resources an economic life of twenty-five years or more.⁷⁵ As explained in Section IV.A., the capital budgeting model used to calculate an ORTP for offshore wind projects should reflect this reality. Assuming a twenty-five-year economic life, NEPOOL's Offshore Wind ORTP Proposal is preferable because it would appropriately permit an additional five years' worth of costs and revenues ("a reasonably conservative benchmark to use in the ORTP for wind resources"⁷⁶) and reduces the FCM payment requirement for offshore wind resources, which is an appropriate start to arriving at a reasonably accurate ORTP.

⁷² See Delaney/Macrae Joint Test. at 11:7–8; 12:22–13:5.

⁷³ See Krich Test. at 21:14–15; <u>Attachment N-1c</u>, Testimony of Ms. Carolyn Gilbert at 9:3–7 (Gilbert Test.).

⁷⁴ See CEA Dec. Report at 76–77. Because the ISO's calculated ORTP for offshore wind came in higher than the FCA Starting Price, the ISO's proposal would apply a default offer floor price of \$11.978/kW-month, i.e., the Starting Price for FCA 16. See ISO Clean Tariff § III.A.21.1.1 (showing that the ISO has not include an ORTP value for offshore wind); ISO Dec. 31 Filing at 5 (explaining that the FCA Starting Price is the higher of CONE or 1.6 multiplied by Net CONE).

⁷⁵ See footnote 43 and accompanying text.

⁷⁶ Krich Test. at 12:3–4.

ii. The estimated overnight capital cost used to calculate the NEPOOL-approved ORTP for offshore wind is more consistent with expected market conditions than the cost assumptions ISO-NE relied upon.

Developing a reasonable estimate of overnight capital costs reflecting prevailing market conditions is also an important factor used to arrive at a \$0.000/kW-month offshore wind ORTP. To develop a reasonable value, some NEPOOL members, through RENEW Northeast, utilized Daymark Energy Advisors' (Daymark) independent analysis of four recently executed Power Purchase Agreements (PPA) from large New England offshore wind projects with publicly available pricing terms.⁷⁷ As explained in the Gilbert Testimony, "Recently executed offshore wind PPAs in New England offer the best source of information for expected offshore wind capital expenditures in this region," which allows one to gauge "commercial expectations and commitments for offshore wind projects."⁷⁸ On the basis of this analysis, Daymark developed a financial model to calculate the implied capital costs of offshore wind projects to be built in New England.⁷⁹ In nearly all instances, Daymark's model applied the same assumptions that the ISO used in its model.⁸⁰ Daymark's analysis showed that the weighted average of implied capital costs of the four PPAs is \$3,326/kW (2019\$), which is significantly lower than the cost assumption of ISO-NE's consultants.⁸¹ Moreover, Daymark's comprehensive analysis was corroborated by a thorough review of publicly available data conducted by Boreas Renewables (Boreas).

As explained in the Krich Testimony, Boreas' literature review of comparable projects⁸² validates Daymark's implied capital costs for offshore wind.⁸³ The following figure, which demonstrates the trend line of offshore wind capital costs, demonstrates not only that Daymark's analysis falls within a range of reasonableness,⁸⁴ but also that the proprietary, opaque capital cost information of the ISO's consultants is much higher than prevailing market conditions.

⁸¹ *Id.* at 9:3–6.

⁸⁴ See id. at 26:6–11.

⁷⁷ Gilbert Test. at 3:4–5.

⁷⁸ *Id.* at 4:6 - 7, 4:12 - 13.

⁷⁹ *Id.* at 3:9–11; *see* Appendix B to the Gilbert Test. (showing the Daymark Analysis).

⁸⁰ Gilbert Test. at 5:15–16. To review the differing assumptions, see *id.* at 6:9–8:16.

⁸² Or, viewed from a different lens, the literature review is a cross-comparison of the Daymark implied capital costs against other publicly available data.

⁸³ See Krich Test. at 22:22–23 ("Boreas researched and gathered reports providing relevant capital cost data for offshore wind."). Boreas' literature review included every source it located. See *id.* at 22:14–20; *see also* Appendix A to Krich Test. (providing a detailed explanation of the reports that Boreas evaluated).





*Installed Capital Costs

†Overnight Capital Costs (excludes cost of interest during construction)

Both the Daymark and Boreas analyses demonstrate that, under prevailing market conditions, an offshore wind project's overnight capital costs are approximately \$3,000/kW, not nearly \$5,400/kW, as the ISO has assumed.⁸⁶ Indeed, "the publicly available literature indicates that offshore wind capital costs for the FCA 16 timeframe (i.e., COD by June 1, 2025) are much closer to the Daymark analysis and the NEPOOL Alternative."⁸⁷ Succinctly stated, assuming a \$3,326/kW overnight capital cost for calculating NEPOOL's offshore wind ORTP reasonably reflects prevailing market conditions (and in any event certainly does so more than the ISO's assumed cost estimate).⁸⁸

⁸⁵ RENEW presented variations of this chart throughout the NEPOOL stakeholder process vetting the ISO's ORTP calculation. *See e.g.*, RENEW Ne., *Offshore Wind Capital Costs for ORTP Calculation: A Proposed Amendment*, at 7 (Sept. 8–10, 2020), <u>https://www.iso-ne.com/staticassets/documents/2020/09/a6 a iv_renew_amendment_offshore_wind_capital_costs_ortp_calculation.pd</u> <u>f</u>. The final version, as presented here, reflects updates that were made as additional data source were identified and included.

⁸⁶ See Gilbert Test. at 9:3–7.

⁸⁷ Krich Test. at 25:1–3; *see also id.* at 25:12–13 (demonstrating that "offshore wind costs have decreased significantly in recent years").

⁸⁸ *Id.* at 42:16–19 (affirming that the overnight capital cost as part of the Offshore Wind ORTP Proposal "falls squarely in the middle of this expected range of costs while the ISO's proposed assumption of

As such, NEPOOL's proposed inclusion of a \$0.000/kW-month ORTP for offshore wind is just and reasonable and preferable to the ISO's calculation. The method to arrive at this stakeholder-favored ORTP value is faithful to the ISO's stated rationale that ORTPs should be set at a level consistent with expected prevailing conditions. Specifically, the presumed overnight capital cost to support NEPOOL's offshore wind ORTP reflects prevailing market conditions and is supported by an analysis that is corroborated by publicly available data.⁸⁹ In fact, as the Krich Testimony explains, "the NEPOOL Alternative represents a conservative take on the industry's expected capital cost" by using a "middle-of-the-pack estimate."⁹⁰ Moreover, this analysis also shows a convergence of data points between the Daymark Analysis and Boreas' literature review, supporting the capital cost estimate used to develop NEPOOL's offshore wind ORTP, while demonstrating that the ISO's estimate is far less consistent with prevailing conditions.

NEPOOL's offshore wind ORTP is preferable to the ISO's proposed approach for two core reasons, among others. First, the NEPOOL-supported proposal is grounded in a reasonably accurate estimate of capital cost supported by publicly available data.⁹¹ The ISO's proposal, by contrast, is over sixty percent higher.⁹² During the NEPOOL stakeholder process, the ISO claimed that the information used by its consultants to calculate the ISO's overnight capital costs was "confidential."⁹³ Second, by not including an offshore wind ORTP, the ISO effectively walks away from a core purpose of developing ORTPs, namely, to screen out *only* those offer

\$5,358/kW falls outside of the range cited by any source for a somewhat comparable project with a commercial operation date within seven years of the reference ORTP project").

⁸⁹ Moreover, a recent study conducted by NYSERDA also offers compelling support. In that study, NYSERDA conducted a bottom-up analysis of the capital costs for an offshore wind projects. Krich Test. at 29:9–11 (explaining that "the NYSERDA report provides a detailed breakdown of the capital cost for its 'base case' project with a project description nearly identical to the 800 MW ORTP reference unit"). Its evaluation produced a capital cost value of \$3,155/kW. *Id.* at 27:9–12. Thus, the NYSERDA study offers yet another publicly available source underscoring the point that NEPOOL's Offshore Wind ORTP Proposal is relying on a reasonable overnight capital cost value that is consistent with prevailing market conditions.

 90 *Id.* at 21:7–10. The Daymark Analysis demonstrated that a reasonable range of capital costs for the four PPAs was between \$2,486/kW to \$4,021/kW. *Id.* at 20:10–16.

⁹¹ Gilbert Test. at 3:11 n.1 (providing citations and hyperlinks to the publicly available information); Krich Test. at 22:14–16 (affirming that "Boreas reviewed every publicly available data source it was able to find regarding the capital costs for offshore wind technologies of a similar scale and timeframe as the ISO's reference ORTP project").

⁹² Krich Test. at 35:8–9.

⁹³ *Id.* at 30:16 (explaining that the ISO "relied on confidential data"); *see also* CEA Dec. Report at 76 (stating that the ISO's consultants relied on MM's "proprietary database" and, without providing citations or attempting to identify, "publicly available information"); Memorandum from Mark Karl, Vice President, to the NEPOOL Participants Committee, subject: ISO's Feedback on the Recommendation by the NEPOOL Markets Committee on Proposed FCM Parameter Values for Forward Capacity Auction 16 (FCA 16), at 2 (Nov. 30, 2020) (page 251 of PDF), <u>https://www.iso-ne.com/static-assets/documents/2020/12/npc-20201203-composite6.pdf</u>.

prices "that plainly appear commercially implausible absent out-of-market revenues."⁹⁴ In contrast, NEPOOL's proposal sets the offshore wind ORTP at "the low end of the spectrum"⁹⁵ and represents a competitive offer floor price based on prevailing market conditions. Accordingly, the NEPOOL Offshore Wind ORTP Proposal offers the Commission a preferable choice to the ISO's proposal.

D. The NEPOOL Alternative reflects enhancements to the ORTP adjustment process for FCAs 17 and 18.

The current Tariff mandates that the ISO adjust ORTPs in certain limited respects for the two intervening years between full recalculations—in this case, FCAs 17 and 18. The process employed by ISO-NE to adjust the ORTPs is guided by Section III.A.21.1.2(e), which enumerates the factors it would use to conduct the adjustment.⁹⁶

The ISO ORTP Proposal offers new Tariff redlines stating that it will include the following ITC inputs when adjusting the Photovoltaic Solar ORTP: (1) twenty-two percent ITC for FCA 17; and (2) ten percent for FCA 18. Generally, the ISO has explained that these percentages are based on "start-of-construction" dates (which are thirty months prior to the start of the applicable Capacity Commitment Period (CCP)) to meet the tax law's existing safe harbor provisions. The following table summarizes the ISO's proposal (and related assumptions concerning its presumed "start-of-construction" dates).⁹⁷

Table 298ISO-NE's Proposed ITC Inputs for Solar							
FCA (CCP Start Date)	Start of Construction Before	Safe Harbor COD Deadline	ITC				
17 (June 1, 2026)	Jan. 1, 2024	Dec. 31, 2027	22%				
18 (June 1, 2027)	Jan. 1, 2025	Dec. 31, 2028	10%				

The components of NEPOOL's PTC/ITC Proposal reflect a preferable approach for the ORTP adjustments of FCAs 17 and 18. NEPOOL's proposal consists of two components, each discussed in turn. First, it proposes the following ITC inputs for the solar ORTP adjustments: (1) twenty-six percent for FCA 17 versus the ISO's twenty-two percent; and (2) twenty-two

⁹⁴ 142 FERC ¶ 61,107 at P 38.

⁹⁵ *Id.* at P 39.

⁹⁶ <u>Attachment I-Ii</u>, ISO-NE Marked Tariff § III.A.21.1.2(e).

⁹⁷ *Id.* § III.A.21.1.2(e)(6).

⁹⁸ *Id.* (providing a scheduled ITC phase down, starting with twenty-six percent for FCA 16, followed by twenty-two and ten percent, respectively, for the upcoming FCAs); Concentric Energy Advisors, Inc. & Mott MacDonald, *ISO-NE ORTP Analysis*, at 8 (Feb. 9, 2021), <u>https://www.iso-ne.com/static-assets/documents/2021/02/a05_mc_2021_02_09_10_iso_ortp_analysis.pptx</u>.

percent for FCA 18 versus the ISO's ten percent.⁹⁹ Unlike the ISO, NEPOOL's proposal is based on the realistic assumption that a solar project will employ a profit-maximizing strategy, which in this case means to leverage the safe harbor provisions of the tax law by "beginning construction" earlier that the ISO assumes, to maximize their ITC eligibility.¹⁰⁰ This assumption supporting the NEPOOL PTC/ITC Proposal is preferable to the ISO's proposed approach because it better aligns with solar industry practice.

The following table offers the relevant data for the "start-of-construction" assumptions used to support the NEPOOL's ITC inputs in Tariff Section III.A.21.1.2(e).

Table 3 NEPOOL's Proposed ITC Inputs for Solar							
FCA (CCP Start Date)	Start of Construction Before	Safe Harbor COD Deadline	ITC				
17 (June 1, 2026)	Jan. 1, 2023	Dec. 31, 2026	26%				
18 (June 1, 2027)	Jan. 1, 2024	Dec. 31, 2027	22%				

With respect to the ITC inputs for solar resources, the NEPOOL-supported Tariff language aligns with the solar industry's standard practice of seeking to maximize tax credits, namely, the ITC.¹⁰¹ For example, in FCA 17 a solar project that reaches COD by December 31, 2026 can start construction soon enough to qualify under the safe harbor provisions for twenty-six percent ITC. To reach this COD, a solar project must begin construction (as defined by the Internal Revenue Code¹⁰²) prior to January 1, 2023. Beginning construction, for tax law purposes, does not necessarily mean putting shovels into the ground. Rather, as routinely done in the industry, a solar project can incur five percent of project costs as early as four years prior to COD. By doing so, a solar project can ensure through the safe harbor provisions that it has maximized its ITC eligibility.¹⁰³ As it relates to a solar resource's ORTP for FCA 17, if for example a solar project incurs five percent of costs for materials, e.g., purchasing a small portion

⁹⁹ See NEPOOL Marked Tariff § III.A.21.1.2(e)(6).

¹⁰⁰ Indeed, "it is only reasonable to assume that a developer would seek to maximize its profits." Krich Test. at 46:18. This strategy would be "weighing the costs and benefits of spending a small amount of money earlier than might otherwise be necessary in order to meet the safe harbor requirements to achieve the highest possible tax benefit under the current tax law." *Id.* at 46:19–21.

¹⁰¹ See id. at 47:21 - 48:19.

¹⁰² I.R.S., Notice 2021-05, *Beginning of Const. for Sections 45 & 48; Extension of Continuity Safe Harbor for Offshore Projects & Fed. Land Projects*, at 4 (2021), <u>https://www.irs.gov/pub/irs-drop/n-21-05.pdf</u> (Notice 2021-05).

¹⁰³ See Krich Test. at 47:21–48:2 (stating that "[m]any solar developers choose to purchase a portion of their equipment years in advance of when they expect to use it because it allows them to take advantage of higher ITC levels, a benefit that is far higher than the carrying cost of holding that equipment for a number of years or the risk of the equipment losing value should the project fail to reach commercial operation").

of the project's solar panels,¹⁰⁴ by December 31, 2022 and reaches COD by December 31, 2026, then it retains a twenty-six percent ITC.¹⁰⁵ As similar analysis and outcome is reached for FCA $18.^{106}$

The second component of NEPOOL's PTC/ITC proposal accounts for a situation where federal tax law changes prior to the annual ORTP calculation adjustment. Specifically, the NEPOOL Alternative inserts Tariff language in Section III.A.21.1.2(e) that allows the ISO to account for the most current federal tax law so that the ORTPs for every technology type would be adjusted by, among other things, inputting into the capital budgeting model the most current credit allowed under federal tax law for PTC and/or ITC.¹⁰⁷ To be clear, the PTC/ITC Proposal does not require the ISO or the IMM to speculate on the future tax law landscape. Rather, it would only require the ISO to reflect the PTC and/or ITC applicable *at the time* the ORTPs are adjusted.¹⁰⁸ And further, the PTC/ITC Proposal does not affect any ORTPs proposed by either ISO-NE or NEPOOL for FCA 16.

Due to the critical importance of federal tax credits for developers, especially those developers seeking to finance and build new renewable resources like solar and offshore wind,¹⁰⁹ NEPOOL's approach is preferable to that of the ISO's because it would fully take into account the available PTC and/or ITC during the inter-year ORTP adjustments. Indeed, the importance of the PTC/ITC Proposal recently came into striking focus when the Act became law allowing offshore wind and solar projects to avail themselves to thirty and twenty-six percent federal tax credit if construction begins before January 1, 2026 and January 1, 2023, respectively. Under the ISO's initial proposal that was voted in early December 2020, the adjustments to the ORTPs for FCAs 17 and 18 *would not* have included this change in tax law, and the ITC assumption would have remained fixed at the zero and ten percent values, respectively, which the ISO had assumed for FCA 16.

Collectively and individually, the components of NEPOOL's PTC/ITC Proposal reflect reasonable and preferable approaches for when the ORTPs are adjusted in FCAs 17 and 18.

¹⁰⁴ *Id.* at 48:3–5 (explaining that, "[d]ue to the modular nature of solar photovoltaic generators, much of the equipment used in the construction of a solar generator is non-site specific (e.g., solar panels, inverters, and even some transformers)").

¹⁰⁵ See Notice 2021-05 at 4 (stating that, *inter alia*, if "a taxpayer pays or incurs (within the meaning of Treas. Reg. § 1.461-1(a)(1) and (2)) five percent or more of the total cost of the facility," a developer can avail itself of the Five Percent Safe Harbor. See 26 C.F.R. § 1.461-1 (providing the meaning "pays or incurs").

¹⁰⁶ Krich Test. at 47:5–8 (confirming that the "same logic applies for FCA 18 with dates and eligibility shifted one year into the future").

¹⁰⁷ NEPOOL Marked Tariff § III.A.21.1.2(e)(6).

¹⁰⁸ Thus, if either PTC or ITC were unavailable at the time of the adjustment, then the ISO (or the IMM) would not include it in the capital budgeting model.

¹⁰⁹ Krich Test. at 44:12–13 ("PTC and ITC policies are important considerations when developing renewable energy projects.").

E. NEPOOL's Proposed ORTP for Battery Storage.

As detailed in the initial CEA/MM Report, the ISO's consultants selected the lithium ion storage facility as the battery storage facility for the ORTP analysis.¹¹⁰ To calculate this technology's ORTP, according to that Report, the expected revenues, which includes energy and ancillary services (E&AS) revenues, are subtracted from gross CONE.¹¹¹ As part of this exercise for the lithium ion storage technology, the ISO's consultants used a so-called "reserve mode" dispatch model, which resulted in an ORTP of \$2.912/kW-month.¹¹² As explained in the Griffiths Memorandum, that model materially underestimates the amount of E&AS revenues a competent battery operator could expect to receive.¹¹³

NEPOOL proposes a lower Energy Storage Device – Lithium Ion Battery ORTP, setting it at \$2.601/kW-month for FCA 16, a value that is well within a zone of reasonableness.¹¹⁴ The Battery ORTP Proposal is reasonable and preferable to the ISO's alternate approach because it relies on an optimization-based battery dispatch model that better accounts for the trade-offs between providing different market services and, consequently, generates a more realistic estimate of the baseline E&AS revenues a competent operator would expect to earn in the market.¹¹⁵ In other words, the NEPOOL battery ORTP is one that better reflects market expectations, which is shown in a reasonable battery dispatch model developed by Mr. Benjamin Griffiths from the Massachusetts Attorney General's Office (MA AGO).¹¹⁶ This dispatch mode, which is analogous to one suggested by the ISO's External Market Monitor,¹¹⁷ showed that a reasonably competent storage operator can earn approximately \$523,000 (2025\$) per year more than what the ISO's model shows.¹¹⁸ Due to this increase in revenues, the ISO's proposed lithium ion battery ORTP was reduced by \$0.311/kW-month (as reflected in the NEPOOL Alternative).¹¹⁹

¹¹⁴ See Louisville Gas & Elec. Co., et al. LG&E Energy LLC, 114 FERC ¶ 61,282 at P 29 (2006) (affirming that "the just and reasonable standard under the FPA is not so rigid as to limit rates to a 'best rate' or 'most efficient rate' standard" and that "a range of alternative approaches often may be just and reasonable").

¹¹⁵ Griffiths Mem. at 8 (stating that the AGO's "dispatch approach . . . reflects the revenue available to a reasonably competent storage operator").

¹¹⁶ Id. at 2–3; see also id. at 9–13 (providing technical details on the dispatch model).

¹¹⁷ *Id.* at 3.

¹¹⁸ *Id.* at 4 (showing, in Table 1, that subtracting \$8.289M (CEA revenues) from \$8.812M is \$523,000).

 119 Krich Test. at 54:5–6 ("This difference is a result of the Energy and Ancillary Service . . . revenue assumption used in the model to calculate the ORTP for the battery.").

¹¹⁰ CEA Dec. Report at 81.

¹¹¹ *Id.* at 88–89.

¹¹² *Id.* at 89; *see id.* at 88–89 (describing the reserve mode).

¹¹³ Benjamin W. Griffiths, "Revenue for Energy Storage Participating in ISO-NE Energy and Reserves Markets," at 3–7 (Mar. 17, 2021) (Griffiths Mem.) (affixed as Appendix A to the Affidavit of Mr. Benjamin W. Griffiths, <u>Attachment N-1e</u>).

NEPOOL's preferred battery storage ORTP value reflects a competitive offer consistent with expected prevailing market conditions, whose value is based on a battery dispatch model that better reflects how a "reasonably competent storage operator"¹²⁰ would operate a battery to maximize revenues.

F. The Combined Resources ORTP Proposal

New England is experiencing a material increase of market activity in resources consisting of multiple technology types behind a single point of interconnection (POI), such as a solar photovoltaic system paired with a lithium ion battery energy storage system. Indeed, such combined resources, cleared in recent FCAs.¹²¹ Like any other New Capacity Resource, ORTPs must be assigned for these resources. Unlike the ORTP treatment of other new, stand-alone single technology capacity resources, the current Tariff proscribes that "[w]here a new resource is composed of assets having different technology types, the resource's [ORTP] will be calculated . . . with the weighted average formula[.]"¹²² Although unartfully written, the formula is simple: "For a new capacity resource composed of assets having different technology types], i.e., a hybrid resource,¹²³] the [ORTP] shall be the weighted average of the [ORTPs] of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type."¹²⁴

¹²⁰ Griffiths Mem. at 8.

¹²¹ See e.g., Press Release, ISO New England Inc., New England's Forward Capacity Auction Closes with Adequate Power System Resources for 2023-2024, at 1 (Feb. 5, 2020), <u>https://www.iso-ne.com/static-assets/documents/2020/02/20200205_pr_fca14_initial_results.pdf</u>.

¹²² Tariff § III.A.21.1.1.

¹²³ Because words have meanings and the Tariff does not offer definitions for all of them, it is worth explaining how the words "resource," "asset," and "hybrid resource" are understood in New England. A "resource" refers to a capacity resource participating in the FCM. ISO New England Inc., Market Participation Options for Combined Intermittent/Electric Storage Facilities, at 7 (Apr. 2020). https://www.iso-ne.com/static-assets/documents/2020/04/20200408-co-located-market-participation.pdf (ISO-NE Training Material). An "asset" is a facility that participates in the energy market. Id. Every resource is associated with one or more assets but the opposite is not true; an asset does not necessarily have to be associated with a resource. Id. A "hybrid resource" is (1) a resource that has one or more assets (2) that share a common point of interconnection and (3) participates in the FCM as a single capacity resource. Id. at 15. See also Attachment N-1f, Testimony of Ms. Sarah Bresolin Silver at 3:18-20 (Bresolin Silver Test.); Post-Technical Conference Comments of ISO New England, Inc., Docket No. AD20-9-000, at 2 (Sept. 2020) (ISO-NE Comments). A "co-located resource" is (1) a resource that has one or more Assets (2) that share a common POI, and (3) where each Asset participates in the FCM as a separate and distinct capacity resource. Bresolin Silver Test. at 3:20-4:2; ISO-NE Training Material at 11–13. Importantly, the assets comprising a co-located resource have separate Asset identification numbers and may offer, schedule, and settle independently, as well as may be owned and operated by independent entities. Bresolin Silver Test. at 5:11-14.

¹²⁴ Tariff § III.A.21.2(c) (footnote added). As background information, in 2014, the ISO proposed the weighted average formula in response to the Commission's rejection, in part, of certain ORTPs. *See* ISO New England Inc. and New England Power Pool, *Market Rule 1 Revisions to the Offer Review Trigger Price Rules for On-Shore Wind and Distributed Generation Resources for FCA 9*, at 8, Docket No. ER14-1477-000 (filed Mar. 13, 2014). As it relates to this instant jump ball filing, the Commission did not

i. Overview of the applicability of "Weighted Average Formula."

To understand the application of the weighted average formula in the ISO-NE Tariff, consider a hybrid resource (which participates as a single New Capacity Resource in the FCM) that is composed of a solar Asset and a battery Asset sharing a POI, as illustrated in Figure 2.



Figure 2: Example of a Hybrid Resource Configuration Composed of a Hybrid Asset¹²⁵

approve the ISO's proposes revisions that would have specified that for a New Capacity Resource composed of Assets having different technology types, such resource's ORTP would be the highest of the applicable ORTPs. Id. at 5. The Commission concluded that using the higher of the applicable ORTP could "result in an illogical ORTP" for the relevant resources. Id. Thus, the ISO proposed the weighted average formula, which "applie[d] . . . to any capacity resource composed of assets with more than one technology type." See ISO New England Inc. and New England Power Pool, Testimony of Robert V. Laurita, Docket No. ER14-1477-000, at 7:10-11 (filed Mar. 13, 2014). In other words, if a new generating capacity resource was composed of a combustion turbine and of a combined cycle unit, each with their respective ORTPs, the weighted average formula applies. Memorandum of David LaPlante, Vice President of Market Monitoring, to NEPOOL Participants Committee, subject: Further revisions to the Offer Review Trigger Price rules for the 9th FCA, at 2 (Mar. 5, 2014), https://www.iso-ne.com/staticassets/documents/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2014/mar72014/npc_201403 <u>07_composite5.pdf</u> (stating that "the IMM has determined that it is appropriate to use the same weighted averaging approach for *all* capacity resource types that are comprised of multiple technology types") (page 226 of PDF). Of course, the Assets are not limited to a combustion turbine or a combined cycle unit.

¹²⁵ The ISO created Figure 2 (as was Figure 3 below). *See* ISO-NE Training Materials at 15. Of note, a hybrid New Capacity Resource can also be the following configuration, as shown in Figure 3, where the technologies not only share the same POI, but also share a single hybrid asset in the energy market.

Pursuant to the current Tariff, the hybrid resource's ORTP "shall be the weighted average" of the solar Asset's ORTP and the battery Asset's ORTP, "based on the expected capacity contribution" from the solar Asset and the battery Asset.

As an example of a possible ORTP of the Figure 2 hypothetical hybrid resource, assume the following: (1) the Commission approves NEPOOL's ORTPs for solar (\$0.000/kW-month) and battery (\$2.601/kW-month); and (2) the solar Asset contributes 100 MW of FCA Qualified Capacity to the hybrid resource, while the battery Asset contributes 50 MW of FCA Qualified Capacity to the hybrid resource. Using the Commission-approved weighted average formula, the hybrid resource's ORTP would be \$0.867/kW-month.¹²⁶

Related to the weighted average formula discussion are "co-located resources" (whose Assets each participate as a separate New Capacity Resources in the FCM), which are depicted in Figure 4.



Figure 3: Example of a Hybrid Resource Configuration Composed of Co-Located Assets ¹²⁶ The calculation for the hypothetical hybrid resource ORTP in a mathematical format is the following:

 $\frac{(100 \text{ MW} \times \$0.000/\text{kW-mo.}) + (50 \text{ MW} \times \$2.601/\text{kW-mo.})}{(100 \text{ MW} + 50 \text{ MW})} = \$0.867/\text{kW-mo.}$



Figure 4: Example of the Co-Located Resource Configuration¹²⁷

Unlike a hybrid resource, which consists of two underlying Assets registering and participating as one single New Capacity Resource, the NEPOOL Alternative clarifies that the weighted average formula does not apply to a co-located resource because it consists of two or more separate FCM resources, each with one underlying Asset(s).¹²⁸ In other words, although co-located resources interconnect at a common point, the underlying Assets are the individual technologies (such as an individual solar asset) that participate separately and individually as a New Capacity Resource in the FCM. Therefore, the weighted average approach would not apply to a co-located resource because it does not have two Assets that would contribute to the single resource's FCA Qualified Capacity.¹²⁹

As an illustrative hypothetical, consider the co-located resource configuration depicted in Figure 4 and assume the Commission approves NEPOOL's FCA 16 ORTPs for solar (\$0.000/kW-month) and battery (\$2.601/kW-month). Logic would follow that Resource 1's ORTP would be set by the underlying single Asset, i.e., solar (\$0.000/kW-month). Likewise, the battery Asset would set Resource 2's ORTP (\$2.601/kW-month). Indeed, Resource 1 and Resource 2 are independent generating capacity resources; thus, the weighted average formula cannot apply.¹³⁰

¹²⁷ Figure 4 was developed by the ISO. *See* ISO-NE Training Materials at 12.

¹²⁸ Bresolin Silver Test. at 7:10–23.

¹²⁹ See 9:6–9; cf. id. at 10:10–11:4 (explaining that the weighted average formula applies to a hybrid resource because the underlying "Assets contribute to the New Capacity Resource's FCA Qualified Capacity," which is not the case with a co-located resource).

¹³⁰ See id. at 9:8–9 (providing an example demonstrating that, in a co-located configuration, "[o]nly one technology type contributes to the FCA Qualified Capacity of each of the New Capacity Resources").

ii. NEPOOL-Approved Tariff clarifications to the applicable provisions.

The NEPOOL Alternative offers enhanced language in Appendix A to Market Rule 1 to clarify three aspects of how an ORTP should be formulated for combined resources, both hybrid and co-located. The new language clarifies that: (1) the weighted average formula applies to hybrid resources (2) the weighted average formula does not apply to assigning an ORTP to co-located resources but rather each single New Capacity Resource would be assigned the relevant technology type ORTP, and (3) the IMM should use the contribution of each technology type towards the resource's FCA Qualified Capacity as the weighted average formula.¹³¹

First, NEPOOL's proposal adds a parenthetical in Section III.A.21.1.1 to provide a specific example of a New Capacity Resource composed of Assets with different technology types.¹³² The other clarification includes the use of Tariff-defined terms rather than undefined terms.¹³³ The purpose of this Tariff language is to affirm that the weighted average formula applies to all hybrid resources and to eliminate any perceived ambiguity as to how the provision is applied. Second, the NEPOOL Alternative proposes new Tariff language in Appendix A, which also uses Tariff-defined terms, to clarify that a co-located resource's ORTP shall be assigned based only on the Asset(s) underlying the resource.¹³⁴ Third, NEPOOL's proposal clarifies that, when performing the weighted average calculation, the IMM will use the contribution of each technology type towards the FCA Qualified Capacity of the resource as the correct way of weighting in the formula.¹³⁵ For all sets of revisions, NEPOOL's Combined Resources ORTP Proposal provides additional clarity by replacing undefined terms with Commission-approved Tariff defined terms and ensures that, for FCA 16, the ORTPs for combined resources—hybrid and co-located alike—are calculated in an appropriate manner.

The Joint Sponsors¹³⁶ of this amendment advocated for this proposal to provide clarity and certainty in the market, particularly for new hybrid and co-located resources looking to participate in the FCM. Without further clarity Market Participants are unable to make sufficiently informed and reasonable business decisions that are essential to participate in the FCM and to compete fairly with other FCM resources.¹³⁷ The Combined Resources ORTP Proposal presents a just and reasonable means to clarify that the weighted average formula applies to hybrid resources but not to co-located resources.¹³⁸ Finally, the NEPOOL-approved Tariff changes specifying how the IMM will apply the weighted average calculation to hybrid resources provide helpful clarifying language that is viewed as "fundamental to administering a

- ¹³³ See Bresolin Silver Test. at 7:8–10.
- ¹³⁴ NEPOOL Marked Tariff § III.A.21.1.1; Bresolin Silver Test. at 7:10–13.
- ¹³⁵ Bresolin Silver Test. at 8:16–22.
- ¹³⁶ *Id.* at 3:7–10 (listing the Joint Sponsors).
- ¹³⁷ *Id.* at 13:18–21.

¹³¹ *Id.* at 6:20–8:22.

¹³² NEPOOL Marked Tariff § III.A.21.1.1.

¹³⁸ In other words, the NEPOOL supported Tariff revisions remove any ambiguity that co-located resources will not have their ORTPs set by the weighted average formula. *Id.* at 7:9–23.

transparent and fair FCA qualification process."¹³⁹ In the past, the Commission has encouraged and even directed RTOs/ISOs to include clarifying language in respective regional tariffs.¹⁴⁰. NEPOOL respectfully requests that the Commission accept analogous clarifying Tariff language provided in the NEPOOL Alternative.

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.¹⁴¹ The NEPOOL Proposal, however, does not change a traditional "rate" and neither the ISO nor NEPOOL are traditional investor-owned utilities. In light of these circumstances, NEPOOL submits the following additional information in substantial compliance with relevant provisions of Section 35.13 and requests a waiver of Section 35.13 of the Commission's regulations to the extent that content or form deviates from the specific technical requirements of regulations.

35.13(b)(1) – Materials included herewith are identified more specifically on pages 2–3 of this transmittal letter and the joint transmittal letter accompanying part 1 of this filing.

35.13(b)(2) –NEPOOL requests that the changes to Market Rule 1 (i.e., the NEPOOL Alternative) become effective June 8, 2021.

35.13(b)(3) – Pursuant to Section 16.11(a)(iv) of the Second Restated NEPOOL Agreement and Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. 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 Attachment I-Ik. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified in Attachment I-Ik to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

¹³⁹ *Id.* at 14:3–8.

¹⁴⁰ See, e.g., ISO New England Inc., 156 FERC ¶ 61,144 at P 18 (2016). Indeed, the Commission routinely encourages and directs RTOs/ISOs to include clarifying language into their respective Tariffs. *E.g.*, *PJM Interconnection*, *L.L.C.*, 171 FERC ¶ 61,153 at PP 271–72 (2020) (directing certain modifications "to clarify" a process); *Dominion Energy Mktg.*, *Inc. et al. v. ISO New England Inc.*, 155 FERC ¶ 61,121 at P 21 (2016) (directing the ISO to add clarity and specificity by filing Tariff language to "expressly address[]" the issue raised in that proceeding); *Sw. Power Pool, Inc.*, 144 FERC ¶ 61,224 at P 129 (2013) (directing to add a "clear definition" and "to make a number of revisions" to clarity a tariff); *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,285 at P 111 (2004) (encouraging tariff modifications to add clarity).

¹⁴¹ 18 C.F.R. § 35.13 (2020).

35.13(b)(4) – A description of the materials submitted pursuant to this filing is contained in this pages 2–3 of this transmittal letter.

35.13(b)(5) – The reasons for this filing are discussed in Sections V through VI of this transmittal letter.

35.13(b)(6) – As discussed in Section V of this transmittal letter and in more detail in <u>Attachment N-1g</u>, the changes to the Tariff reflect the results of the Participant Processes required by the Participants Agreement. The NEPOOL Alternative was approved by a NEPOOL Vote of 72.50%.

35.13(b)(7) – NEPOOL 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(b)(8) – A form of notice and electronic media are no longer required for filings in light of the Commission's Combined Notice of Filings notice methodology.

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

35.13(c)(2) – ISO-NE 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 NEPOOL Alternative's Tariff revisions filed herein.

VIII. CONCLUSION

For the reasons stated in this transmittal letter and in the attached supporting material, the Commission should approve the NEPOOL Alternative, which is just and reasonable and preferable to the ISO ORTP Proposal.

Respectfully submitted,

NEPOOL Participants Committee

By:

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Its Attorneys

Dated: April 7, 2021

Attachment N-1b

Testimony of Abigail Krich

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UNITED STATES OF AMERICA BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.

Docket No. ER21-___-000

PREPARED TESTIMONY OF ABIGAIL KRICH

)

1 I. INTRODUCTION

2 Q: Please state your name, title, and company description.

3 My name is Abigail Krich.¹ I am the founder and president of Boreas Renewables, LLC A: 4 ("Boreas"), a consulting practice serving renewable energy resource developers, owners, 5 operators, and advocates including RENEW Northeast ("RENEW"). Founded in 2008, Boreas 6 specializes in helping developers navigate their way through the ISO New England 7 interconnection process, participate in the Forward Capacity Market ("FCM"), and register to 8 sell into the New England wholesale electricity markets. Boreas works with energy resource 9 owners and operators to understand how existing and upcoming market rules and compliance 10 requirements factor into their day-to-day operations. In addition to following the evolving 11 markets, Boreas actively advocates within the New England Power Pool ("NEPOOL") and ISO 12 New England Inc. ("ISO-NE" or "the ISO") stakeholder process for electricity market rules and 13 system planning improvements that will allow for the development and integration of high levels 14 of renewable energy.

¹ My full legal name is Abigail Krich Starr, but my professional name is Abigail Krich.

1 Q:

Please describe your relevant work experience and education.

2 A: Among the positions I have held in the field of renewable energy over the past nineteen 3 years, I was a Senior Project Developer at Tamarack Energy; an independent consultant 4 performing wind energy resource assessments; an electrical/mechanical designer at Northern 5 Power Systems in the distributed generation project engineering group; a graduate intern at the 6 National Wind Technology Center at the National Renewable Energy Laboratory working 7 primarily with the grid integration group; and an intern at Berkshire Photovoltaic Services. I was 8 elected to serve as Vice-Chair of the NEPOOL Variable Resource Working Group, which I have 9 done since the group's inception in 2014. I have passed the Fundamentals of Engineering exam 10 and hold a Bachelor of Science in Biological and Environmental Engineering, as well as a 11 Master's of Engineering in Electrical and Computer Engineering, both from Cornell University.

12 **Q:**

Have you previously testified in regulatory proceedings?

13 A: Yes. I list my testimony experience below:

Testimony before the Federal Energy Regulatory Commission ("FERC" or the
 "Commission") regarding capacity factors at New England wind farms and implications
 for the FCM, submitted on behalf of RENEW, First Wind, and Conservation Law
 Foundation, on January 23, 2014, in Docket No. ER14-616.

Testimony before the Maine Department of Environmental Protection on behalf of
 Conservation Law Foundation, regarding the economic and environmental impacts of
 wind energy in Maine, for the Champlain Wind public hearing on May 1, 2013.²

² Pre-Filed Testimony of Abigail Krich on Behalf of Intervenor Conservation Law Foundation, ME DEP Docket No. L-25800-24-25800-TE-B-N (Mar. 13, 2013).

- Testimony before the Maine Land Use Regulation Commission, submitted on behalf of
 Conservation Law Foundation regarding the economic and environmental impacts of
 wind energy in Maine, for the Champlain Wind public hearing on June 28, 2011.³
- Testimony before the Maine Public Utilities Commission ("MPUC") on behalf of
 Highland Wind in support of Central Maine Power Company's petition to construct the
 Somerset County Reinforcement Project Consisting of the Construction of
 Approximately 39 Miles of 115 kV Transmission Lines (i.e., "Section 241") before the
 MPUC, May 26, 2011.⁴
- 9 Q: In what capacity are you submitting this testimony?

10 A: I am submitting this testimony in my capacity as consultant to RENEW, an industry 11 organization that advanced seven modifications to the ISO's proposal regarding the Offer 12 Review Trigger Prices ("ORTP") to be used in the FCM (the "ISO ORTP Proposal"). Within the 13 NEPOOL stakeholder process, these modifications were offered individually, each in the form of 14 an amendment to the ISO's ORTP proposal or as a motion to amend NEPOOL's previously 15 adopted ORTP proposal. NEPOOL members discussed each of the modifications and approved them by the supermajority vote needed for NEPOOL approval. At its December 3, 2020 16 17 Participants Committee meeting, NEPOOL approved an alternative market rule proposal to the 18 then-ISO ORTP proposal that consolidated four RENEW-sponsored amendments, as well as a 19 another NEPOOL-approved amendment that had been advanced and advocated for by Enel X

³ Pre-Filed Direct Testimony of Abigail Krich on Behalf of the Conservation Law Foundation, Development Permit DP 4889, ME Land Use Reg. Comm'n (June 10, 2011), <u>https://www.maine.gov/dacf/lupc/projects/windpower/firstwind/champlain_bowers/Development/Applica</u> tion/Testimony/CLF_KrichBowersTestimony-2011-06-10.pdf.

⁴ Rebuttal Testimony of Abigail Krich on Behalf of Highland Wind, LLC, ME PUC Docket No. 2010-00180 (May 26, 2011), <u>https://mpuc-</u>

cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=60699&Case Number=2010-00180.

North-America ("Enel") and Borrego Solar Systems ("Borrego"). Later, at its March 24, 2021
 meeting, the Participants Committee approved additional amendments to modify its earlier
 December 3 approved ORTP proposal. All of the RENEW-sponsored amendments relate to how
 ORTPs will be established prospectively, while the Enel/Borrego-sponsored amendment relates
 to how resource-specific offer floor prices will be established prospectively.

6 Q: What is RENEW?

7 RENEW is a non-profit association uniting the renewable energy industry and A: 8 environmental interest groups whose mission involves coordinating the ideas and resources of its 9 members with the goal of promoting and increasing renewable energy in New England and New 10 York. RENEW works to create and strengthen the public policies that will lead to the 11 development and integration of high levels of renewable energy production for the benefit of the 12 region. Modeled after successful organizations in other parts of the country, RENEW was 13 initially a collaborative project of the wind industry and public interest environmental 14 organizations. RENEW's goal is to recruit as members other renewable energy companies, 15 suppliers, utilities and manufacturers that share a common vision of clean, renewable and 16 environmentally responsible power development. RENEW strives to be a single, coherent voice 17 for its membership to achieve renewable energy and greenhouse gas reduction goals by sharing 18 resources and aligning messages. RENEW takes a leadership role in policy development on 19 renewable energy issues before ISO New England and NYISO, state legislatures, governors, and 20 utility commissions.

1 **O**: Please describe your involvement in the NEPOOL and ISO-NE stakeholder process 2 related to the FCM parameters.

3 A: Boreas has been active, on behalf of RENEW, in the stakeholder process related to all 4 four ORTP calculations performed by ISO-NE, starting in 2012 with the eighth Forward Capacity Auction ("FCA"). In this instant recalculation for FCA 16, Boreas identified a number 5 6 of concerns related to the assumptions proposed by ISO and its consultants regarding the clean 7 energy resource ORTPs and developed the ORTP amendments that are part of the NEPOOL 8 Alternative.

9 To support my development of the RENEW-sponsored amendment related to offshore 10 wind, RENEW engaged Daymark Energy Advisors ("Daymark") to develop a financial model to 11 calculate the capital costs that could be supported by the recent New England offshore wind 12 power purchase agreements with publicly available pricing terms. Working together with my 13 Boreas colleague, I used the results from Daymark's model to calculate the offshore wind ORTP 14 value contained in the NEPOOL Alternative. As discussed below, Boreas benchmarked the 15 Daymark results through an extensive literature review.

16

What is the purpose of your testimony? **Q**:

17 A: The purpose of my testimony is to explain why the RENEW-sponsored elements of the 18 NEPOOL Alternative are individually and collectively not only just and reasonable but also preferable to those in the ISO ORTP Proposal. 19

1 II. <u>Summary of Support for NEPOOL Alternative</u>

- 2 Q: Please list the technology-specific ORTPs proposed to be used in FCA 16.
- 3 A:

Proposed ORTPs for New Generating Capacity Resources					
Technology Type	ISO-NE ORTPs (\$/kW-mo.)	NEPOOL-supported ORTPs (\$/kW-mo.)			
Simple Cycle Combustion Turbine	\$5.355	\$5.355			
Combined Cycle Gas Turbine	\$9.811	\$9.811			
On-Shore Wind	\$0.000	\$0.000			
Off-Shore Wind	FCA Starting Price	\$0.000			
Energy Storage Device – Lithium Ion Battery	\$2.912	\$2.601			
Photovoltaic Solar	\$1.381	\$0.000			

4 Q: What is the NEPOOL Alternative?

5 A: The NEPOOL Alternative is the collective set of amendments to the ISO ORTP Proposal 6 that were supported by NEPOOL. Briefly, they include the following: (1) a new defined term, 7 "New Capacity Resource Economic Life" ("Economic Life"), and use of a longer Economic Life 8 for solar and wind technologies, which impacts the ORTPs for solar and offshore wind (the 9 "Economic Life Proposal"); (2) an ORTP value for offshore wind (the "Offshore Wind ORTP 10 Proposal"); (3) Tariff language that would, for the intervening FCAs before the next triennial 11 update, adjust the ITC value for solar resources based on the current tax law and permit further 12 adjustments as applicable to reflect the current tax treatment each year for the federal Production 13 Tax Credit ("PTC") and Investment Tax Credit ("ITC") (the "PTC/ITC Proposal"); (4) revisions 14 to the ORTP value for lithium-ion battery resources (the "Battery ORTP Proposal"); (5) 15 clarifications to the applicability and method for calculating the ORTP for resources that share a 16 point of interconnection; and (6) Tariff language to clarify that a new capacity resource, during 17 the unit-specific offer review process, can submit documentation to justify an Economic Life 18 greater than 20 years and to help determine a unit's weighted average cost of capital. The first

four elements above of the NEPOOL Alternative were advocated for by RENEW and are
 addressed in this testimony.

3 Q: Why is the NEPOOL Alternative preferable to the ISO Proposal?

A: As described below, each of the components of the NEPOOL Alternative provide a more
accurate formulation of the ORTPs consistent with prevailing industry and market expectations,
especially for clean energy projects, which increasingly will be a part of the supply mix in New
England.

8 Q: Please give a high-level overview of the substance of your testimony below.

9 A: Section III addresses the Economic Life Proposal. In it, I explain why adding the 10 proposed definition to the Tariff and using it for wind and solar resources will ensure the ISO 11 more fully captures the expected costs and revenues of wind and solar projects over their 12 projected lifetimes, consistent with the assumptions used by developers making commercial 13 commitments and prevailing market conditions. Section IV, which is the longest section, 14 addresses the Offshore Wind ORTP Proposal. In it, I explain the basis for the proposed offshore 15 wind ORTP value in the NEPOOL Alternative, including the capital cost analysis supporting it, 16 the corroboration of that analysis by an extensive literature review, and a response to the ISO's 17 criticism of the capital cost analysis. Section V addresses the PTC/ITC Proposal. In it, I explain 18 why it is appropriate and feasible for the ISO to update the PTC/ITC percentages for FCAs 17 19 and 18 for solar resources to be 26% and 22%, respectively, consistent with current tax law, and 20 why these values and all other PTC/ITC values should be updated consistent with any further 21 changes to those provisions of the tax law. Section VI addresses the Battery Storage ORTP Proposal. In it, I explain why that proposal is more accurate than the ISO's proposal. Section VII 22 23 is the brief conclusion. In Appendix A to this testimony, I provide further details on the literature

review discussed in Section IV. In Appendix B to this testimony, I offer a response to criticisms
 to the Offshore Wind ORTP Proposal.

3 III. ECONOMIC LIFE PROPOSAL

4 Q: What is the purpose of the Economic Life Proposal?

5 A: The purpose of the Economic Life Proposal is to recognize that the 20-year economic life 6 term currently in the ISO-NE Transmission, Markets and Services Tariff ("Tariff"), while 7 possibly reasonable to use for some resources, is an unnecessarily brief economic life term to use 8 for other types of resources such as onshore/offshore wind and photovoltaic solar. Unnecessarily 9 shortening the assumed economic life of these types of resources in calculating ORTPs 10 inappropriately raises the values of their ORTPs, as demonstrated below, particularly for solar 11 and offshore wind resources. By using a default 20-year cap for the economic life of these types 12 of resources, the ISO is effectively ignoring well-documented evidence and data that supports a 13 longer economic life for these technology types.

14 Q: Please describe and explain the NEPOOL Alternative's proposed definition of "New 15 Capacity Resource Economic Life."

16 A: The proposed definition of a "New Capacity Resources Economic Life," defines the New
17 Capacity Resource's economic life as the lesser of:

- a. The period of time that a New Capacity Resource of a given technology type or
 types would reasonably be expected to operate before the resource becomes
 unprofitable for at least two consecutive years;
- b. the expected physical operating life of the resource; or
- 22 c. 35 years.

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Attachment N-1b – Testimony of Abigail Krich

1 A rational capacity resource owner will continue to operate its asset until it becomes 2 consistently economically unprofitable. Said another way, a capacity resource owner has no 3 economic reason or motivation to retire an asset that is still profitable. The NEPOOL Alternative 4 reflects the reasonable conclusion that two years' worth of unprofitability is sufficient to 5 conclude that unit's economic life has reached its end, even though a case could be made for an 6 even longer economic life if future profitability beyond two years of losses could be projected. 7 We concluded that one year of unprofitability alone would be insufficient to declare the 8 economic life for a particular type of resource to be ended because profitability could have been 9 impacted by, for example, a large scheduled maintenance expense required for certain types of 10 resources, with the expectation that such resources would become profitable again in future 11 years. Part (a) of the proposed definition captures this economic principle.

12 Clearly, a resource cannot expect to operate profitably beyond its expected physical 13 operating life and the economic life should be capped at this potentially shorter period. This was 14 the intention of part (b) of the proposed definition. The physical operating life of the resource 15 reflects the amount of time the technology can reasonably be expected to operate based on its 16 engineering design before the entire system would be at risk of failure. The operating life of the 17 resource includes standard maintenance and component replacement as needed to keep the 18 facility operating at its rated capacity but does not include total replacement of the entire asset.

19 If the resource's expected period of profitability and the operating life are expected to be 20 greater than 35 years, then part (c) of the definition caps the Economic Life at 35 years. For this 21 part of the definition, the assumption is that 35 years is the maximum reasonable economic life a 22 resource could justify. Based on current information, economic lives beyond 35 years would 23 likely be speculative and inappropriate to use in developing ORTPs.

9

- 1 III.1. The proposed new definition "New Capacity Resource Economic Life" is just,
 2 reasonable, and preferable.
- 3 Q: What is a reasonably expected economic life for wind energy facilities?

A: A reasonable expected economic life for both offshore and onshore wind facilities is 25
to 30 years. In recent years, researchers and industry professionals have been using at least 25
years to model wind facilities and expect to continue to use this assumption (if not longer) for
future projects as wind technology continues to mature. I believe that 25 years is a reasonable
and conservative estimate for the economic life for wind technologies to calculate the ORTP for
FCA 16.

10 This economic life assumption is also supported by our own direct conversations and 11 work with developers and industry professionals. Possibly more compelling, a recently published 12 Lawrence Berkley National Laboratory ("LBNL") report demonstrates that wind professionals 13 currently anticipate project lifetimes far longer than the ISO's standard 20-year economic life 14 assumption.⁵ The LBNL wind report notes that not a single wind industry professional surveyed 15 anticipates a lifetime of a project less than 25 years and that most wind developers anticipate project lifetimes of 30 years.⁶ These professionals represent U.S. wind project developers, 16 17 sponsors, financiers, and consultants from 18 organizations. In addition to the survey, LBNL 18 reviewed "annual financial reports from some of the large, publicly traded wind project

⁵ Ryan Wiser & Mark Bolinger, *Benchmarking Anticipated Wind Project Lifetimes: Results from a Survey of U.S. Wind Industry Professionals*, Lawrence Berkeley Nat'l Lab. Electricity Mkts. & Policy Grp., at 2 (Sept. 2019), <u>https://eta-publications.lbl.gov/sites/default/files/wind_useful_life_report.pdf</u>.

⁶ *Id.* at 3 (noting that "[n]one of the respondent uses a 20-year project life assumption").

- 1 developers and owners."⁷ From its survey and review of financial reports, LBNL developed the
- 2 following figure⁸ that shows current expectations of useful lives for wind plants.



Figure 1. Current Useful-Life Expectations for Wind Plants

3

Importantly, as documented in the LBNL report, lifetime expectations for wind facilities have changed recently as the technology continues to mature. As part of its research, LBNL created the following figure⁹ showing how expectations of useful life have changed over the years for 20 different respondents. Each orange trace is a different respondent and how its expectation of useful life has changed over time. The blue trace is the average of each of the individual traces for each year.

Figure 2. Useful-Life Expectations for Wind, over Time



10

⁷ *Id*. at 1.

⁸ *Id.* at 2.

⁹ *Id.* at 3.

As shown in the figure, the expectation of useful life of wind plants has recently grown from around 20 years to nearly 30 years. However, while many developers may be expecting 30-year economic lives, I believe 25 years is a reasonably conservative benchmark to use in the ORTP for wind resources.

5 In addition, a search of other recent literature on wind technologies strongly supports the 6 conclusion that 25 years is a reasonable expected life of future wind projects. In the Energy Information Administration's ("EIA") Annual Energy Outlook,¹⁰ the operating lifetime for all 7 8 wind technology use-cases was 25 years. Similarly, the International Renewable Energy Agency 9 ("IRENA") uses a standard 25-year economic life in its levelized cost of energy ("LCOE") calculation for wind power technologies.¹¹ Likewise, in 2018 the New York State Energy 10 11 Research and Development Authority ("NYSERDA") selected and contracted with two offshore wind project proposals, totaling nearly 1,700 megawatts with a contract tenor of 25 vears.¹² 12 13 NYSERDA stated that these projects' lifetimes are expected to exceed the 25-year contract terms.¹³ NYSERDA's second phase offshore wind solicitation in 2020, which resulted in the 14

¹⁰ U.S. Energy Info. Admin., *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, at 20-4, 21-4, 22-3 (Feb. 2020), <u>https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf</u> ("EIA Report").

¹¹ Int'l Renewable Energy Agency, *Renewable Power Generation Costs in 2019*, at 138 (2019), <u>https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Jun/IRENA_Power_Generation_Costs_2019.pdf</u> ("IRENA Report").

¹² This selection was done pursuant to the New York State Public Service Commission's July 2018 Order Adopting the Offshore Wind Standard, which sets the framework for the first phase of its offshore wind solicitations. N.Y. State Energy Research & Dev. Auth., *Launching New York's Offshore Wind Industry: Phase 1 Report*, at 1–2, 22 (Rev. Oct. 2019), <u>https://www.nyserda.ny.gov/-/media/Files/Programs/offshore-wind/osw-phase-1-procurement-report.pdf</u>.

¹³ See id. at ii, S-3, 27.

selection of two additional projects totaling 2,490 MW,¹⁴ similarly allowed for proposed contract
 terms of up to 25 years.¹⁵

3 Q: What is a reasonably expected economic life for photovoltaic solar?

A: A reasonable expected economic life for a photovoltaic solar facility is 30 to 35 years.
Again, recently published reports regarding project lifetimes and a survey of industry
professionals point to economic lives longer than ISO's standard assumption of 20 years. We
believe that 30 years is a reasonable and conservative estimate for the economic life for solar
technologies to calculate the ORTP for photovoltaic solar for FCA 16.¹⁶

9 In a parallel study to the wind lifetime report outlined above, LBNL published another report on the expected lifetimes for solar projects.¹⁷ The report showed that solar professionals 10 11 currently anticipate project lifetimes far longer than the ISO's standard assumption. Of the solar 12 industry professionals surveyed, only two anticipate lifetimes less than 30 years and most 13 anticipate lifetimes greater than 30 years, with 42 percent of respondents anticipating lifetimes greater than 35 years.¹⁸ These solar professionals represent developers, sponsors, financiers, and 14 15 consultants from seven organizations and were benchmarked against "annual financial reports from some of the large, publicly traded solar project developers and owners."¹⁹ The figure below 16

¹⁴ N.Y. State Energy Research & Dev. Auth., 2020 Offshore Wind Solicitation (Closed), https://www.nyserda.ny.gov/All%20Programs/Programs/Offshore%20Wind/Focus%20Areas/Offshore%2 0Wind%20Solicitations/2020%20Solicitation (last visited April 1, 2021).

¹⁵ N.Y. State Energy Research & Dev. Auth., *Purchase of Offshore Wind Renewable Energy Certificates Request for Proposals ORECRFP20-1*, at 15 (updated Sept. 2020), https://portal.nyserda.ny.gov/servlet/servlet.FileDownload?file=00Pt0000000PfCVEA1.

¹⁶ See EIA Report at 24-4 (using 30 years for the operating life of a solar photovoltaic project).

¹⁷ Ryan H. Wiser et al., *Benchmarking Utility-Scale PV Operational Expenses and Project Lifetimes: Results from a Survey of U.S. Solar Industry Professionals*, Lawrence Berkeley Nat'l Lab. Electricity Mkts. & Policy Grp. (June 2020), <u>https://eta-publications.lbl.gov/sites/default/files/solar_life_and_opex_report.pdf</u>.

¹⁸ See id. at 1.

¹⁹ *Id*.
1 summarizes the results of the LBNL survey, which shows a clear consensus among solar



2 professionals that the economic life of solar projects is 30 years or longer.²⁰



As with wind power, the expected economic life of solar facilities has increased over time. The LBNL report published the figure below that summarized this change in expectations.²¹ Each orange trace is a different respondent and how their expectation has changed over time since 2007. The blue trace is the average of each of the individual traces for each year.





3



²¹ *Id*.

²⁰ *Id.* at 3.

As shown above, a 20-year economic life for solar resources reflects industry expectations from over 10 years ago. Although the 20-year standard assumption may have been appropriate in previous ORTP calculations, this is no longer the case. Clearly, solar projects today expect economic lifetimes longer than 20 years. While many professionals may expect economic lives greater than 35 years, I believe 30 years is an appropriate, conservative benchmark to use in calculating the photovoltaic solar ORTP, as these expected lives are still somewhat uncertain.

8 Q: Why would it be an improvement to include in the ISO Tariff the Economic Life 9 definition as proposed in the NEPOOL Alternative?

10 A: Adding this definition will ensure the ISO more fully captures the expected costs and 11 revenues of wind and solar projects over their projected lifetimes and reflects the full economic 12 value of the resources, consistent with the assumptions used by developers making commercial 13 commitments, as well as prevailing industry/market expectations and conditions.

In addition, although power purchase agreements ("PPAs") for wind and solar projects in New England might not typically exceed 20 years currently, it is reasonable to expect these facilities would have a "merchant tail" period during which they would sell directly into the wholesale markets after expiration of the term of their PPAs. Developers count and plan on these merchant tails in their models when making financial decisions, extending lifetimes well beyond 20 years. Because ORTPs are supposed to be based on prevailing commercial expectations, the ORTP should be set based on the economic lifetimes that resource owners are actually using.

Developers are currently making financial decisions based on an assumption of longer
 economic lives. By waiting to change this assumption for a future ORTP recalculation process,

as the ISO has suggested in the stakeholder process, the ISO is not capturing current market
 expectations and is inappropriately setting the ORTP too high for wind and solar technologies.

Therefore, the NEPOOL-approved Economic Life Proposal is a reasonable and marked improvement to the status quo. It increases accuracy by requiring the ISO to take into account the more likely period of expected costs and revenues for offshore wind and solar projects in developing ORTPs for these types of resources. Greater accuracy will, in turn, lead to ORTPs that better reflect prevailing market conditions.

8

III.2. The impacts of the Economic Life Proposal on ORTPs.

9 Q: How does the NEPOOL Economic Life Proposal impact the ISO's ORTP model?

10 A: Although the NEPOOL Economic Life Proposal applies to all technology types, it only 11 affects the ISO's ORTP model for wind and solar generation. Instead of modeling cash flows 12 over 20 years, the NEPOOL Alternative models cash flows over 25 years for onshore and 13 offshore wind and 30 years for solar. All revenues and expenses in the NEPOOL Alternative 14 extend to the technology's full economic life, including capacity payments, which are directly 15 used to determine the ORTP.

By extending the economic life for wind and solar facilities, the ORTP for these resources decreases. This reduction occurs because the facilities are now recognizing net revenues from energy, ancillary services, pay-for-performance, scarcity, and renewable energy credits in years beyond year 20. The more net revenue the resource receives outside of capacity payments, the lower the capacity payments will need to be to make the resource whole. The ORTP is based on the capacity payments the resource needs to be whole.

Q: How does applying the NEPOOL Economic Life Proposal affect the offshore wind ORTP?

A: In isolation of the other elements of the NEPOOL Alternative, changing the economic
life for the offshore wind technology from 20 years to 25 years decreases the ORTP by
\$6.840/kW-month, from \$17.948/kW-month to \$11.108/kW-month.

6 Q: How does applying the NEPOOL Economic Life Proposal affect the onshore wind 7 ORTP?

A: Changing the economic life for the onshore wind technology from 20 years to 25 years
decreases the calculated ORTP by \$4.667/kW-month, from \$(11.783)/kW-month to
\$(16.450)/kW-month. Thus, the resulting ORTP for onshore wind under the NEPOOL
Alternative is unchanged from the ISO proposal and remains \$0.000/kW-month.

12 Q: How does applying the NEPOOL Economic Life Proposal affect the photovoltaic
 13 solar ORTP?

A: Changing the economic life for the photovoltaic solar technology from 20 years to 30
years decreases the calculated ORTP by \$7.872/kW-month, from \$1.381/kW-month to
\$(6.491)/kW-month. Thus, the resulting ORTP for photovoltaic solar under the NEPOOL
Alternative is \$0.000/kW-month.

18 Q: Does applying the NEPOOL Economic Life Proposal affect any other ORTPs, Cost
19 of New Entry ("CONE"), or Net CONE?

A: The NEPOOL Economic Life proposal does not affect any of the other ORTPs, CONE,
or Net CONE values for FCA 16. The NEPOOL Alternative still uses a 20-year economic life
for all fossil fuel technologies and the Energy Storage Device Lithium Ion Battery. In addition,
the Economic Life Proposal does not affect the Demand Capacity Resources' ORTPs.

However, the Economic Life Proposal does change the Tariff such that 20 years is no 1 2 longer a fixed required modeling assumption for future calculations. In future ORTP 3 calculations, the New Capacity Resource Economic Life of each of the reference units will have 4 to be determined, just as the other technology-specific assumptions are determined, as part of the 5 ORTP recalculation process. As the economic lives of resources continue to change, the 6 NEPOOL Alternative eliminates an unrealistic and stagnant standard and allows for the 7 flexibility needed for the ORTPs to accurately capture prevailing market expectations as 8 intended.

9 IV. OFFSHORE WIND ORTP PROPOSAL

10 Q: What is the Offshore Wind ORTP Proposal in the NEPOOL Alternative?

11 A: The Offshore Wind ORTP Proposal uses a capital cost assumption of \$3,326/kW 12 (2019\$), which more accurately reflects expected prevailing market conditions than the 13 assumption proposed by ISO-NE. The NEPOOL Alternative's proposed capital cost, which is 14 lower than that proposed by ISO-NE, is based on Boreas' extensive review and analysis of publicly available information. Using that lower capital cost results in a calculated FCA 16 15 16 ORTP of \$(3.625)/kW-month for offshore wind. However, when combined with the Economic 17 Life Proposal, this proposal results in a calculated FCA 16 ORTP of \$(7.867)/kW-month for 18 offshore wind, which is reflected with a \$0.000/kW-month ORTP for offshore wind in the 19 NEPOOL Alternative. The Offshore Wind ORTP Proposal in the NEPOOL Alternative, unlike 20 the ISO-NE proposal, is an accurate representation of current prevailing competitive market 21 conditions for this technology.

Q: Please describe the review and analysis that was done regarding the capital cost of offshore wind.

A: At the request of RENEW, Daymark performed an analysis of recently executed New England offshore wind PPAs, creating a financial model that calculates the level of capital cost that could be supported by each of the contracted projects. Boreas then benchmarked this analysis by conducting a literature review of every publicly available data source we were able to find regarding capital costs for offshore wind of a similar scale and timeframe as the ORTP reference unit.

9

10

IV.1. A review of the Daymark analysis that supports the Offshore Wind ORTP Proposal.

11 Q: Please provide a high-level description of the Daymark analysis.

12 A: Daymark created a financial model that calculates the level of capital cost that an 13 offshore wind project could support given a set of assumptions about such things as project 14 revenues, operating costs, project performance, and financing terms. As background, there are 15 four PPAs for three offshore wind projects to be built off the coasts of Massachusetts and Rhode 16 Island with publicly available contract terms. Under these binding contracts, the offshore wind 17 projects will sell the entirety of their energy and Renewable Energy Certificates ("RECs") for the 18 first twenty years of the project's operation at pre-defined prices, resulting in a high level of 19 certainty regarding the expected revenues for each project.

Given the high level of certainty that exists regarding the expected revenues for offshore wind projects with executed long term PPAs, Daymark used its financial model to analyze the three such projects that exist in New England for which PPA terms are publicly available, namely, the Vineyard Wind, Revolution Wind, and Mayflower Wind projects. Using the known,

contracted revenues in Daymark's financial model, along with nearly all of ISO-NE's
 assumptions regarding operating costs, project performance, and financing terms, Daymark was
 able to solve for the capital cost that could be supported by each project.

The recently executed PPAs in New England provide the best source of information for expected offshore wind capital expenditures, as they represent actual commercial expectations and binding commitments that have been made for projects precisely like the hypothetical ORTP project being modeled by the ISO.

8 Q: What did the Daymark analysis show regarding the expected capital costs of 9 offshore wind projects in New England?

10 A: The Daymark model²² shows a \$2,486 to \$4,021/kW (2019\$) range of supportable 11 project capital costs for the four PPAs evaluated under two capacity pricing scenarios. If looking 12 at only the more conservative capacity pricing scenario of \$6/kW-month, the weighted average 13 supportable capital cost for the four PPAs is \$3,326/kW (2019\$). This is the value used in the 14 NEPOOL Alternative. The individual findings for each contract evaluated are shown in the 15 following table.

Project	Capacity (MW)	Supportable CapEx (2019\$/kW)			
		\$2 capacity scenario	\$6 capacity scenario		
Vineyard Wind Tranche 1	400	\$3,451	\$3,796		
Vineyard Wind Tranche 2	400	\$2,856	\$3,201		
Revolution Wind Tranche 1	400	\$3,675	\$4,021		
Mayflower Wind	804	\$2,486	\$2,809		
Capacity Weighted Average		\$2,990	\$3,326		

16	Offshore wind capital costs, as well as resulting PPA prices, have been rapidly trending
17	down in recent years. For the most recent contract signed in New England with publicly

²² The Daymark model is included as Appendix B to <u>Attachment N-1c</u>, Ms. Carolyn Gilbert's Testimony.

a vailable terms—the contract for the Mayflower Wind project—the Daymark analysis calculated a range of supportable capital cost between \$2,486/kW and \$2,809/kW. Of the contracted projects evaluated, Mayflower is most similar to the ORTP reference unit; its contracted commercial operation date ("COD") in 2025 is the same as the reference unit and its contracted project size of 804 MW is nearly identical to the ISO's 800 MW reference unit. Mayflower's supportable capital cost is well below the NEPOOL Alternative assumption of \$3,326/kW.

By using a weighted average of the New England offshore wind projects that Daymark evaluated rather than using only the most recent and lowest-cost project, the NEPOOL Alternative represents a middle-of-the-pack estimate of industry expectations rather than a low end of the range. Further, by using only the values calculated from the more conservative Daymark scenario that assumes the project is able to earn \$6/kW-month in capacity revenue for its full qualified capacity, the NEPOOL Alternative represents a conservative take on the industry's expected capital costs.

14 Daymark's analysis demonstrates that the ISO-NE proposed capital cost assumption of 15 \$5,358/kW is entirely outside the range of supportable costs. It is sixty-one percent higher than 16 the weighted average value used in the NEPOOL Alternative and thirty-three percent higher than 17 the highest individual capital cost estimated in the Daymark analysis, i.e., Revolution Wind 18 Tranche 1. It is difficult to imagine that any one of the developers behind these projects, let alone all of them, would have signed binding contracts for their project's output at a purchase price 19 20 that would only support a small fraction of their expected costs, as ISO-NE's proposal implies. 21 As discussed later, if the developers behind these projects expected capital costs equal to the ISO proposal, the contracts they signed would have locked them into expected losses of 22 23 approximately \$1.3 billion each, on average, per 800 MW project.

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Attachment N-1b – Testimony of Abigail Krich

1 Q: The ISO has stated that their proposed capital cost value is at the very low end of 2 the range of what could be considered reasonable. Is your assumed offshore wind capital 3 cost too low?

A: No. Based on my analysis of the Daymark findings, the offshore wind capital cost assumption used in the NEPOOL Alternative is in the <u>middle</u> of the range of expected capital costs for large scale offshore wind projects to be built off the coast of New England in the FCA 16 timeframe. In other words, the assumed offshore wind capital cost is not at the low end or below the range of expected costs. By contrast, the ISO-proposed capital cost assumption is well above the range of expected costs found in the Daymark analysis. These conclusions are corroborated by the literature review Boreas performed.

11IV.2. An overview of the Boreas literature review that supports the Offshore Wind12ORTP Proposal.

13 Q: Please describe Boreas' literature review to benchmark the Daymark analysis.

A: To confirm the findings of the Daymark analysis were reasonable, Boreas reviewed every publicly available data source it was able to find regarding the capital costs for offshore wind technologies of a similar scale and timeframe as the ISO's reference ORTP project. Without bias as to whether it supported one assumption or another, Boreas included in this review every publicly available data source it found, to reflect the full range of cost expectations in the literature. A detailed discussion of each of the data sources Boreas reviewed is included in Appendix A to the testimony

21 Q: How did you conduct the literature review?

A: Boreas researched and gathered reports providing relevant capital cost data for offshore
wind. While some of these reports rely on national or global data beyond New England, Boreas

1 worked to ensure that it appropriately compared the numbers in these reports against the ISO's 2 ORTP reference unit, while noting differences. Where a data source reported on a range of 3 values rather than a single point value, we reported the entire range of expectations unless 4 otherwise noted in Appendix A. Because the United States, including New England, should be 5 included in any national or global cost projections for future years, we have no reason to believe 6 that New England costs should fall outside these cited projected ranges. Even if the numbers in 7 individual reports are not directly comparable to the project being analyzed in the ISO's ORTP 8 calculation, this broad range of reports provides a reasonable benchmark for the full range of 9 expectations for capital costs for offshore wind projects. Because the ISO's capital cost 10 assumption for offshore wind does not fall within-or even near-this range for recent and 11 future projects, we do not believe it represents a reasonable capital cost estimate for the offshore 12 wind project in the FCA 16 ORTP calculation.

13 Q: What were the overall results of the literature review?

14 The chart below graphically displays a summary of the findings of our literature review. A: 15 The twenty-four data points represent a broad array of sources. Some data points represent cost 16 projections using a variety of estimating methodologies, while others represent actual reported 17 costs for projects that are now operating. The data points come from governmental entities in the 18 United States (the U.S. Energy Information Administration, the U.S. Department of Energy, the 19 National Renewable Energy Laboratory, the U.S. Environmental Protection Agency, the New 20 York Public Service Commission, and NYSERDA), an intergovernmental agency (IRENA), an 21 independent financial advisory firm (Lazard), specific offshore wind projects (Cape Wind, 22 Dominion), ISO-NE and other ISOs (NYISO, PJM), and the results of the Daymark analysis.²³

²³ A detailed discussion of each data point shown in this figure is included in Appendix A.

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Attachment N-1b – Testimony of Abigail Krich

1 The data in the figure is organized left to right by the actual or expected year of the 2 offshore wind project's COD, with each COD year shown in a different colored band. Where it 3 was possible to do so, only data from large-scale projects over 400 MW in size were included 4 because these larger projects are most comparable to the ISO's 800 MW ORTP reference unit. 5 Some of the reported costs shown here are total capital costs while others are "overnight" capital 6 costs, which exclude the cost of financing during construction. The figure differentiates between 7 the two types of capital costs: installed capital costs and overnight capital costs. Overnight costs 8 are lower than installed costs due to the exclusion of these financing costs. Where a specific 9 source was initially included in our review and that source was later found to have a more recent 10 report available, we include both the outdated data (shown in grey) and the newer updated data. 11 The reports that were updated were, from left to right, IRENA 2018, Lazard 2019, EPA 2018, 12 and DOE 2018.



Publicly Available Offshore Wind Capital Costs Estimates

^{*}Installed Capital Costs

[†]Overnight Capital Costs (excludes cost of interest during construction)

As can be seen, the publicly available literature indicates that offshore wind capital costs for the
 FCA 16 timeframe (i.e., COD prior to June 1, 2025) are much closer to the Daymark analysis
 and the NEPOOL Alternative. The higher capital cost assumed by ISO-NE stands in stark
 contrast.

Additionally, the results from Daymark's analysis for the four individual offshore wind contracts evaluated fall squarely within the range of the other data sources for large-scale projects in a similar timeframe. The weighted average of the Daymark findings for the more conservative scenario (shown in green and labeled as "NEPOOL Alternative") is within the middle of the range of costs reported by the eleven independent sources of data for projects with CODs of 2019 or later.²⁴ The ISO ORTP Proposal (shown in red and labeled as "ISO-NE 2020") falls well above the range of all eleven of these sources.

12 The literature review figure also clearly shows that offshore wind costs have decreased 13 significantly in recent years. The capital costs shown for projects with CODs in the 2016–2018 timeframe are markedly higher than those for 2019 and beyond. This is particularly well 14 15 illustrated by two of the data points in the figure, namely, the IRENA 2018 and IRENA 2019 16 values. These represent the actual reported costs of large-scale offshore wind projects that were 17 built in Europe in 2018 and 2019, respectively. The ISO-NE proposal falls within the upper end 18 of the range of reported costs for large European projects that reached COD in 2018. The range 19 of costs for 2019 COD projects, as reported by IRENA in June 2020, was dramatically less than 20 the 2018 COD costs. The decrease between 2018 and 2019 was so significant that the ISO ORTP 21 Proposal no longer falls anywhere near the reported range for 2019 project costs. Had it been proposed in the prior round of ORTP calculations four years ago, the ISO-NE proposed capital 22

²⁴ The eleven independent sources referenced are those other than the Daymark findings and the ISO Proposal with a COD between 2019 and 2026.

cost assumption would have been an accurate representation of then-current expected costs in
 this industry. But, there has been a dramatic and demonstrated reduction in offshore wind costs
 in recent years that is unjustifiably ignored in the ISO Proposal.

4 Q: In light of the results of Boreas' literature review, what is your opinion regarding
5 Daymark's conclusions?

A: The literature review corroborated the Daymark analysis and the conclusion that significantly lower capital costs for offshore wind are appropriate. Together, the two studies converged to show that a much lower capital cost for offshore wind than what the ISO proposed is reflective of current conditions in the offshore wind industry for projects similar to the ORTP reference unit. More reflective of current conditions means more accurate and more appropriate to use in setting the ORTP for offshore wind.

12 Q: Did you provide some analysis in the NEPOOL stakeholder process of your 13 literature review?

A: Yes. Boreas presented the literature review that we conducted to benchmark Daymark's analysis at five Markets Committee meetings. In a memo dated October 30, 2020, Boreas and RENEW provided a detailed look at the data underlying this literature review.²⁵ Appendix A to this testimony includes an updated version of that detailed summary of the literature review, together with responses to related comments from ISO's consultant, Concentric Energy Advisors ("CEA").

²⁵ Letter from RENEW Northeast to Mariah Winkler, Chair, NEPOOL Markets Committee, subject: RENEW FCA 16 ORTP Calculation Assumptions Report Offered as Rebuttal to Concentric Energy Advisors' Presentation at the October Markets Committee Meetings (Oct. 30, 2020), <u>https://www.ne-rto.net/static-assets/documents/2020/11/a4_b_x_renew_memo_re_offshore_wnd_ortp.pdf</u>.

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Attachment N-1b – Testimony of Abigail Krich

1 **O**: From your literature review, is there one individual source that stands out to you? 2 Yes, the June 2020 whitepaper from NYSERDA and the New York State Department of A: 3 Public Service ("NY DPS") provides an instructive comparison to the cost-estimate for offshore 4 wind done by the ISO. The NYSERDA/NY DPS base case cost estimate is for an offshore wind 5 project that is in large part identical to the ISO's reference ORTP project. Both are 800 MW projects in the northeastern United States with 2025 CODs that use 12 MW turbines and AC 6 7 interconnections. While the location and interconnection site of the ISO's reference unit is 8 Massachusetts, the NYSERDA base case project is located off the coast of New York and would 9 interconnect to New York. In the following figure it is clear that the NEPOOL Alternative capital cost of \$3.326/kW aligns closely with the NYSERDA/NY DPS base case cost of \$3.155/kW.²⁶ 10 11 both of which are well below the ISO's \$5,358/kW (all in 2019\$).



²⁶ Table 14 on page 29 of Appendix A of the NYSERDA whitepaper lists a total cost of \$3,218 in 2020\$. We have adjusted this to 2019\$ assuming 2% inflation. N.Y. State Energy Research & Dev. Auth., *White Paper on Clean Energy Standard Procurements to Implement New York's Climate Leadership and Community Protection Act Appendix A—Cost Analysis*, Case 15-E-0302, at 29 (June 18, 2020), file:///H:/Downloads/%7BDCA9763C-D2DA-4FD1-9801-D859E7ED8FE3%7D.pdf ("Appendix A NYSERDA"). For a description of the White Paper, see *New York Advances Framework to Implement the State's Climate Law and Decarbonize its Power Sector*, N.Y. State Energy Research & Dev. Auth. (June 18, 2020), https://www.nyserda.ny.gov/About/Newsroom/2020-Announcements/2020-06-18-New-York-Advances-Framework-to-Implement-the-States-Climate-Law-and-Decarbonize-its-Power-Sector.

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Attachment N-1b – Testimony of Abigail Krich

1 It is worth noting that the NYSERDA base case cost estimate excludes three smaller line items 2 that are included in the ISO and NEPOOL cost estimates. The ISO and NEPOOL estimates include a small cost (up to tens of millions of dollars) for network upgrades,²⁷ while the 3 NYSERDA base case capital cost estimate excludes network upgrade costs.²⁸ Second, the ISO 4 5 and NEPOOL estimates include financing fees equal to 4% of costs financed through debt and working capital equal to 1% of EPC costs.²⁹ The NYSERDA estimate, as we have confirmed 6 7 through discussion with NYSERDA staff, accounts for financing costs and working capital 8 separately from capital costs. Therefore, the base case capital cost estimate does not include 9 financing costs and working capital.

Added together, these three costs account for approximately \$265/kW of the difference between the NYSERDA estimate and the ISO proposal. This difference hardly explains the \$2,203/kW gap between the NYSERDA base case cost estimate of \$3,155/kW and the ISO's cost estimate of \$5,358/kW.

14 These three costs account for approximately \$138/kW of the difference between the 15 NEPOOL Alternative and the NYSERDA estimate. Because the overall project costs are so 16 similar between the NEPOOL and NYSERDA estimates, it could reasonably be assumed that the 17 financing fees and working capital would be similar between the two. Adding an additional

²⁷ Concentric Energy Advisor's presentation at the August 2020 Markets Committee indicates that system upgrades were included in their cost estimate but does not break out what those upgrades were or what their cost was assumed to be. Nonetheless, because it was part of the ISO's \$55M electrical interconnection line item, the network upgrades can be no more than tens of millions of dollars. *See* Concentric Energy Advisors, Inc. & Mott MacDonald, ISO-NE CONE and ORTP Analysis, Presentation to NEPOOL Markets Committee, at 42 (Aug. 12, 2020), <u>https://www.iso-ne.com/staticassets/documents/2020/08/a4 a iii cea presentation cone and ortp analysis.pdf</u> ("CEA Aug. 2020 PPT").

²⁸ Appendix A NYSERDA at 7.

²⁹ See Concentric Energy Advisors, Inc. & Mott MacDonald, *ISO-NE Net CONE and ORTP Analysis: An Evaluation of the New Cost of New Entry and Offer Review Trigger Price Parameters to be used in the Forward Capacity Auction*, Docket No. ER21-787-000, at 84, 85. (Dec. 2020) ("CEA Report").

\$138/kW to the NYSERDA value, to bring it in line with the ISO and NEPOOL scope, would
 bring the NYSERDA total to \$3,293/kW, which is exceptionally close to the NEPOOL value of
 \$3,326/kW.

4 Q: The NYSERDA report describes making "a series of adjustments" to the base case 5 capital cost for site characteristics, such as water depth and distance to port, but does not 6 detail those adjustments. Without knowing the details of those adjustments, why do you 7 believe the NYSERDA capital cost estimate is for a project comparable to the ORTP 8 reference unit?

9 A: As discussed above, the NYSERDA report provides a detailed breakdown of the capital 10 cost for its "base case" project with a project description nearly identical to the 800 MW ORTP 11 reference unit. The purpose of the NYSERDA report was to look at the expected cost of 12 procuring 9,000 megawatts of offshore wind. The report describes that it did this by starting with 13 a base case project, the one discussed above that is nearly identical to the ORTP reference 14 project, and then making a series of adjustments to the base case estimate to arrive at the 15 assumed cost of the other 8,200 megawatts of offshore wind projects that would be built. The 16 analysis in the report related to the other 8,200 megawatts of offshore wind to be built in other 17 locations at other times is not relevant to the question of what the 800 MW base case project with 18 2025 COD is expected to cost.

Q: The NYSERDA report says its cost estimate was prepared by a consultant, RCG,
based on its proprietary model and cost data. Without being able to see all of the
underlying details in the consultant's data, why do you feel this is a reliable cost estimate?

A: To be clear, Daymark independently calculated estimated capital costs which Boreas
corroborated through an extensive literature review as I described earlier. I see the NYSERDA

1 estimate as further confirmation that our estimate, in contrast to the ISO's, is reasonable and 2 justified. Like the ISO's consultant Mott MacDonald ("MM"), NYSERDA's consultant RCG 3 relied on its proprietary detailed cost data to develop its estimate. But unlike the ISO's cost 4 estimate, the NYSERDA report notes that its offshore wind cost assumptions, and resulting 5 offtake contract premiums, were benchmarked against *actual* offshore wind contract bids 6 received by NYSERDA in response to its 2018 offshore wind solicitation. NYSERDA concluded 7 that project economics "were found to fall within a similar range, providing confidence in the model's underlying technology cost and financing cost assumptions."³⁰ The fact that the results 8 9 of the RCG modeling were benchmarked against actual, recent commercial bids for similar projects (similar in timeframe, scale, location, and design) and found to be within a similar range 10 11 provides us with a high level of confidence that both the NEPOOL and NYSERDA capital cost 12 estimates accurately reflect prevailing industry expectations.

13

IV.3. The ISO's offshore wind capital cost assumption is unjust and unreasonable.

14 **Q**: Was the ISO's offshore wind capital cost assumption similarly benchmarked against 15 actual planned projects similar to the reference unit?

16 A: Because of how the ISO relied on confidential data, I am uncertain. In the ISO's 17 November 30, 2020 memo to the NEPOOL Participants Committee, they noted the following:

18 [T]he ISO has access to estimated capital cost and other financial data for

- 19 offshore wind projects under consideration in New England. While the ISO's
- 20 Information Policy prohibits discussion of those confidential data publicly, they
- 21 provide the ISO and the IMM with an independent 'benchmark' to compare to the
- 22 separately-conducted CEA/MM offshore wind capital cost and ORTP estimates.

³⁰ Appendix A NYSERDA at 7.

1This benchmarking gives the ISO confidence in the reasonableness of the2CEA/MM proposed ORTP values for offshore wind that have been reviewed with3stakeholders. To ensure that the FERC has the benefit of this same information,4the ISO plans to submit the non-public data (confidentially) to FERC for its5consideration of this matter.³¹

6 The ISO was unwilling to confirm the currency or comparability of its data to the reference unit 7 and demonstrated in many of its discussions a refusal to account for industry cost trends. Given 8 how quickly and dramatically costs have come down in recent years, cost estimates that the ISO 9 may have received from projects just two years ago are likely already outdated. The IRENA 10 2019 report (included in our literature review) notes, "For offshore wind, the years 2018 and 11 2019 marked the revelation in auction and tender results of a step change in pricing."³²

12 One of the most significant drivers for this recent cost decrease has been the increase in 13 turbine size, with projects now signing agreements with suppliers of turbines rated at up to 13 14 MW each. This is illustrated by data from the National Renewable Energy Laboratory ("NREL") 15 that shows that the global capacity weighted average installed offshore wind turbine size was about 6 MW for projects completed in 2019, but increases to 11 MW for the projects that have 16 been announced for completion in 2025.³³ If the ISO is benchmarking their cost estimate against 17 18 projects with turbines that are rated less than the 12 MW turbine assumed for the reference unit, 19 or projects that are smaller in size than the 800 MW reference unit and therefore do not include

³¹ Memorandum from Mark Karl, Vice President, to the NEPOOL Participants Committee, subject: ISO's Feedback on the Recommendation by the NEPOOL Markets Committee on Proposed FCM Parameter Values for Forward Capacity Auction 16 (FCA 16), at 2 (Nov. 30, 2020) (page 252 of PDF), https://nepool.com/uploads/NPC_20201203_Composite6.pdf ("Karl Mem.").

³² IRENA Report at 26.

³³ Walter Musial et al., 2019 Offshore Wind Technology Data Update, Nat'l Renewable Energy Lab., at 61 (Oct. 2020), <u>https://www.nrel.gov/docs/fy21osti/77411.pdf</u>.

1 2 the same economies of scale, then these benchmarks cannot be compared apples-to-apples and adjustments would need to be made to account for this significant difference.

3 As one concrete example of project cost reductions in recent years as the industry has 4 matured, the Vineyard Wind offshore wind project brought a series of project design 5 modifications to the NEPOOL Reliability Committee in July 2020. The project's original 6 interconnection System Impact Study was completed in February 2019. Later that year, the 7 project requested a material modification determination to reflect changes as the project has 8 matured. Among the design changes made and discussed with the Reliability Committee, the 9 project switched to fewer, larger turbines and modified its electrical design for cost savings, 10 using a single offshore substation rather than two, reducing the size of its synchronous 11 condensers near the Point of Interconnection, and reducing the size of their submarine cables. 12 Even this change to the project design considered by the ISO in 2020, which reflected the use of 13 10 MW turbines, is now outdated. On December 1, 2020, Vineyard Wind announced the selection of GE as the project's preferred turbine supplier.³⁴ The project announced they would 14 15 be using the GE Haliade-X turbine, which features a rating of 12, 13, or 14 MW according to GE.³⁵ While it is not clear whether the ISO's confidential information includes a cost estimate 16 17 for the Vineyard Wind project, there would be a basis for inaccuracy if ISO-NE were using an 18 older cost estimate from the project before these cost-saving measures were incorporated into the 19 project design.

³⁴ Vineyard Wind, Vineyard Wind Selects GE Renewable Energy As Preferred Turbine Supplier for America's First Utility-Scale Offshore Wind Project (Dec. 2020), https://www.vineyardwind.com/pressreleases/2020/12/1/vineyard-wind-selects-ge-renewable-energy-as-preferred-turbine-supplier.

³⁵ GE Renewable Energy, An Industry First: Haliade-X offshore wind turbine. https://www.ge.com/renewableenergy/wind-energy/offshore-wind/haliade-x-offshore-turbine (last visited Mar. 23, 2021).

Finally, the recent EPA offshore wind cost estimates included in our literature review are illustrative of the cost savings developers have been able to realize in just the last two years. In January 2020, the EPA updated the reference case for their Power Sector Modeling Platform, including an update to their capital cost estimate for a 2025 offshore wind project.³⁶ This update decreased the EPA's estimated cost for a 2025 Massachusetts offshore wind facility from \$4,672/kW in the November 2018 reference case³⁷ to \$3,044/kW in the January 2020 reference case (both adjusted to 2019\$).

8 Q: Why might the ISO's capital cost estimate be more aligned with 2016–2018 COD
9 project costs than expected 2025 project costs?

10 A: The ISO's December 2020 Net CONE and ORTP analysis report by CEA and MM states 11 "[t]he offshore wind capital cost estimate was largely based on benchmarking against large scale 12 projects in the North Sea in which Mott MacDonald has been directly involved."³⁸ This 13 explanation may go a long way towards explaining why the ISO grossly over-estimates capital 14 costs for offshore wind.

One of the projects in the North Sea that we know involved close work by MM is the Gemini project that is 53 miles off the coast of the Netherlands.³⁹ According to MM's website, the total cost for that project was \$3.2 billion, which appears to be the expected project cost from 2014 when Gemini's project financing closed. For this 600-megawatt project, \$3.2 billion

³⁶ See U.S. Envtl. Prot. Agency, *Updates in January 2020 Reference Case*, at 21 tbl. 4-16, <u>https://www.epa.gov/sites/production/files/2020-</u> <u>02/documents/incremental_documentation_for_epa_v6_january_2020_reference_case.pdf</u> ("EPA_Jan. 2020 Reference Case").

³⁷ U.S. Envtl. Prot. Agency, *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model*, at 4-26–4-29 tbls. 4-15, 4-16 (Nov. 2018), https://www.epa.gov/sites/production/files/2019-03/documents/epa platform v6 november 2018 reference case.pdf.

³⁸ CEA Report at 76.

³⁹ Mott MacDonald, *Powering communities with offshore wind*, at 11, <u>https://www.mottmac.com/download/file?id=37754&isPreview=True</u> (last visited Mar. 23, 2021).

equates to a capital cost of \$5,333/kW. While MM has not explicitly stated whether its cost
 estimate for the ISO's ORTP reference unit is based on its experience with the Gemini project,
 the Gemini cost is nearly identical to the ISO's current proposal of \$5,358/kW.

Significant cost differences exist between the Gemini project, which reached COD in 2017, and other recently constructed projects in the North Sea as compared to the ISO's FCA 16 reference unit that has a COD of 2025. For one, the Gemini project used a now obsolete 4megawatt turbine. As discussed above, Vineyard Wind intends to use the Haliade-X offshore wind turbine rated between 12 and 14 megawatts.⁴⁰ Two other planned wind farms in the U.S., which are off the coast of New Jersey and Maryland, have also selected the GE Haliade-X turbines for their projects.⁴¹

11 It appears that technological advances in construction and turbines are evolving so 12 quickly that even a project completed in 2017 (which is eight years prior to the Capacity 13 Commitment Period at issue) is out of date compared to the latest technology. In its report, CEA 14 states that purported "[r]easonable adjustments [to the cost of the North Sea projects MM was involved in] were made to account for US-specific requirements."⁴² CEA, however, has not 15 16 provided any detail on those adjustments. Nor does CEA reflect any consideration of how today's larger turbines result in lower capital costs than those used in previously built projects. 17 18 The CEA/MM report claims to have benchmarked costs "against projects where European EPCs were used,"⁴³ but, as noted above, it appears that the projects used in that benchmarking may 19

⁴³ *Id*.

⁴⁰ GE, *Big Win(d): GE's Powerful Haliade-X Offshore Wind Turbine Gets A Major U.S. Customer*, (Dec. 3, 2020), <u>https://www.ge.com/news/reports/big-wind-ges-powerful-haliade-x-offshore-wind-turbine-gets-a-major-us-customer</u>.

⁴¹ *Id*.

⁴² CEA Report at 76.

have been older European projects and not based on prevailing market expectations for offshore
 wind in 2025.

3 Q: In light of Boreas' literature review and Daymark's work, what is your opinion of 4 ISO-NE's overnight capital cost for offshore wind projects?

5 A: Based on Daymark's analysis, as supplemented by my own thorough literature review 6 and experience working with developers and market participants, I do not believe that the ISO's 7 capital cost assumption of \$5,358/kW accurately reflects prevailing market conditions and industry experience. It is roughly sixty percent higher than the average capital cost expectation 8 9 for comparable projects currently under development. This cost difference alone would cause a 10 \$21.573/kW-month difference in the final offshore wind ORTP value. This difference would 11 result in offshore wind not receiving an ORTP if the ISO proposal is accepted. ISO-NE has not 12 provided enough evidence of its methodology and due diligence in assessing offshore wind 13 capital costs to justify its unrealistically high cost estimate, and this cost estimate cannot 14 reasonably be relied on to support the capital cost assumption used to develop the ORTP for 15 offshore wind.

Due to the convergence and close agreement between the results of the Daymark analysis and the data in the public literature, the results of the Daymark analysis can reasonably be relied on to support the capital cost assumption used to develop the ORTP for offshore wind in the NEPOOL Alternative.

1 IV.4. The criticisms of the Daymark analysis and the Boreas literature review are 2 unavailing.

3 Q: How do you respond to the critique from the ISO and CEA that Daymark's analysis 4 is flawed?

5 A: During the NEPOOL stakeholder process, CEA suggested that implying the capital costs 6 of offshore wind projects from their actual PPA prices, as Daymark has done, does not represent an estimated capital cost due to the many unknowns and assumptions made in the analysis.⁴⁴ 7 8 CEA argued that the recent New England PPA prices that were used in the Daymark analysis 9 may reflect "winner's curse," in which the developer underestimated costs and overestimated 10 benefits, committing to a contract price that does not fully cover their costs. To support this 11 hypothesis, they point out that the cost of the PPAs evaluated for the Vineyard Wind project 12 ranged from \$65/MWh to \$74/MWh, while recent PPAs signed by New York projects had 13 significantly higher first-year prices of \$99.08/MWh, \$86/MWh, and \$160/MWh. They further 14 support their hypothesis that Vineyard Wind may have, either knowingly or unknowingly, signed 15 a contract that would result in a financial loss by presenting the EIA's LCOE for an offshore 16 wind project beginning operation in 2025 of between \$102.68/MWh and \$155.55/MWh, with an 17 average of \$122.25/MWh (2019\$). They further cite the NREL analysis of the Vineyard Wind 18 PPA included in our literature review, which determined that the expected Levelized Revenue of 19 Energy ("LROE") for the Vineyard Wind project was \$98/MWh (2018\$). All of these claims by 20 CEA are wrong, and I explain the reasons why in Appendix B to this testimony.

⁴⁴ See Concentric Energy Advisors, Inc. & Mott MacDonald, ISO-NE CONE and ORTP Analysis, at 4 (Oct. 7, 2020), <u>https://www.iso-ne.com/static-assets/documents/2020/10/a5 b ii cea presentation.pptx</u> ("CEA Oct. 2020 PPT"); CEA Aug. 2020 PPT at 43.

Q: How do you respond to the critique from the ISO's Internal Market Monitor ("IMM") that Daymark's analysis is flawed?

3 A: The IMM issued a memo to the NEPOOL Markets Committee late the evening of 4 November 9, 2020, the day prior to the committee's vote on the ORTP proposals, noting three 5 assumptions used in the Daymark analysis that the IMM disagreed with. Despite Daymark 6 having first presented their model to the Markets Committee at its July meeting and RENEW 7 requesting such feedback multiple times, this was the first specific feedback that we received 8 from the IMM related to any of the assumptions used in the Daymark analysis. We explain here 9 why the IMM's feedback regarding two revenue assumptions should be dismissed as 10 unreasonable. The IMM's feedback related to the third assumption identified to us that we had 11 made an unintentional transcription error, which we promptly corrected the morning of 12 November 10 prior to the Markets Committee vote.

<u>Pay-for-Performance ("PFP"):</u> The IMM stated in its memo: "The [Daymark] model apparently does not fully consider [PFP] revenues which are expected to be material in future years (ISO assumed Performance Payment Rate of \$9,307/MWh as compared to their model using \$3,500/MWh through May 2024 and \$5,455/MWh from June 202[4] forward)."⁴⁵ The IMM correctly identified that the Daymark model used lower Performance Payment Rates ("PPR") than the ISO model for the period starting June 2025 (the commitment period corresponding with FCA 16). The Daymark model sought to determine what revenues the three

⁴⁵ Memorandum from the Internal Market Monitor to NEPOOL Markets Committee, subject: IMM Position on the RENEW Proposal for the Offer Review Trigger Price for Off Shore Wind, at 2 (Nov. 9, 2020), <u>https://www.iso-ne.com/static-assets/documents/2020/11/a4_imm_memo_re_ucs_renew_offshore_wind_amendment.pdf.</u> Of note, at the time of this memorandum, the ISO was proposing a Performance Payment Rate of \$9,307/MWh. This value, however, changed as reflected in the ISO's March 30, 2021 filing in Docket No. ER21-787-001. Moreover, the memorandum appears to have a scrivener's error by writing "June 2025." Rather, the memorandum should have stated "June 2024" because that is the start of the Capacity Commitment Period associated with FCA 15.

1 offshore wind project developers could reasonably have expected when submitting their bids for 2 PPAs. To be conservative and consistent with the ISO's approach, Daymark included PPR 3 revenues in its model. At the time that the developers submitted their bids in 2018 and 2019, the 4 PPR was set at \$5,455/MWh in the Tariff for FCA 15 and beyond. There is no way the 5 developers could have known then to expect the PPR to be raised to \$8,894/MWh in 2021 for 6 FCA 16. Regardless, even had the Daymark model assumed that the developers were prescient 7 and could have anticipated a future PPR rate of \$8,894/MWh, the impact is minor, as it would have changed the implied capital cost by a mere \$15/kW and the ORTP value by about 8 9 0.14/kW-month. Irrespective of the magnitude, this assumption is not a reasonable one, as there 10 is no way the developers could have known this future number at the time of their bid submittals. 11 Merchant Tail: The IMM stated in its memo: "The revenue assumptions used in the final 12 5 years of the analysis are likely understated as they do not appear to include the value of Renewable Energy Credits that would be available to the developer."⁴⁶

14 The ISO's ORTP model includes only 20 years of project revenues. To be more 15 conservative than the ISO assumptions and more closely match what we had initially expected 16 project developers would account for, Daymark included a five-year merchant tail for energy. 17 Interestingly, the IMM in its memo suggests a reasonable offshore wind developer would have 18 been expected to count on both this energy revenue in years 21 through 25, as well as REC 19 revenue, which supports the NEPOOL Alternative to model a full 25-year economic life for wind 20 resources in the ORTP calculation.

21 The IMM was correct that if the Daymark analysis had included a merchant tail for REC 22 revenues, then it would have increased the implied capital costs. However, they appear to be

 $^{^{46}}$ *Id*.

overestimating the impact of this assumption. Even if the Daymark analysis had included this
 REC revenue, the result would still be a negative calculated ORTP value for the offshore wind
 reference unit. In other words, this assumption has no impact one way or another on the resulting
 NEPOOL-approved ORTP for offshore wind.

5 Q: During the stakeholder review process, the ISO and its consultant criticized the data 6 points in the Boreas literature review (as seen in the chart above) as selective or otherwise 7 not valid. How would you respond to that criticism?

8 The ISO and CEA are wrong. They criticize the analysis for relying on current and A: 9 publicly available data simply because that data was not developed using the same estimating 10 methodology used by MM. Instead, they suggest that MM's confidential information, which 11 appears to be MM's potentially dated experience in the North Sea, and opaque "adjustments" are 12 more reliable. While it would have been ideal for the ISO, its consultants, and stakeholders to all 13 rely on data directly from comparable projects to the ISO proposed ORTP reference project 14 developed using the same methodology, the data supporting the NEPOOL Alternative is much 15 more reliable and comparable than the lone publicly verifiable data source referenced by the 16 ISO. All organizations included in the literature review figure above are reputable. The costs 17 they cite reflect their findings on offshore wind capital costs, which have been subject to public 18 scrutiny. As with any estimation or data collection processes, both those used by Boreas and 19 those used by the ISO and CEA, there is the potential for errors and uncertainty.

We used, as should the Commission, expansive, current, publicly verifiable, and reliable data. In each of the descriptions of the data sources in Appendix A, I rank their suitability to be used as a benchmark for use in the ORTP recalculation process. The ranking is based on the quality of the data source, as well as the alignment or discrepancy of the underlying source assumptions with the ISO's reference project. It is important to note how those discrepancies will impact the capital cost values reported by the source. Many of the reported discrepancies (e.g., smaller turbines, smaller projects, or reporting total installed costs rather than overnight costs) result in higher costs than those that would be expected for the particular New England project in question. Correcting for those discrepancies would, in fact, lower the reported value rather than raise it.

7 As noted earlier, Boreas—without bias—included every public source of data it was able 8 to find regarding the capital costs of large-scale offshore wind in a timeframe similar to the 9 ORTP reference unit. We were not selective in the data reported because we wanted to show the 10 full range of actual and expected costs in the industry. To be sure, certain data sources in this 11 literature review are of a higher quality than others, and certain sources provide costs for projects 12 that are more comparable to the ORTP reference unit than others. However, the fact that the 13 capital costs provided by this large number of sources using a wide variety of approaches 14 converge on a fairly small range indicates that there is a well-defined reasonable range of 15 prevailing expectations in the industry. It also shows that the ISO ORTP Proposal is not close, 16 much less within, this range, while Boreas' estimate is in the center of this range.

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IV.5. A "bottom-up" approach to calculate capital cost assumptions for offshore wind is not mandated by the Tariff.

19 Q: The ISO has used a bottom-up approach to calculate its capital cost assumption and
20 Daymark uses a different approach. Does the ISO-NE Tariff allow either approach to be
21 used?

A: Yes. The tariff does not prescribe all the particulars of how the default ORTPs are to becalculated, including what particular method of analysis should be used for developing the

1 assumed capital cost. It only prescribes that a capital cost assumption is to be made and input into the capital budgeting model.⁴⁷ 2

3

While there is some uncertainty inherent in the Daymark analysis about implied capital 4 costs due to the need to make certain assumptions, our extensive literature review confirms that 5 appropriate assumptions have been used given that the results fall well within a reasonable range 6 of expectations. The uncertainty in the assumptions used in the Daymark analysis is no greater 7 than in a pure bottom-up analysis in general. Here, the Daymark analysis is far more accurate 8 than the specific bottom-up analysis used to develop the ISO's proposal. Further, all details of 9 the Daymark analysis were shared publicly, multiple times, during the stakeholder process, 10 providing for full transparency, unlike the ISO's proposed cost estimate which was based upon 11 proprietary and confidential data.

12 **Q**: What is your opinion of a bottom-up versus an alternate method of calculating capital costs for the ORTPs? 13

14 A: As explained above, the ISO's Tariff does not prescribe that the capital cost assumption 15 used in the ORTP model must be calculated using a bottom-up method. In the first ORTP 16 calculation process (for FCA 8), the offshore wind capital cost was determined based on a survey 17 of published cost data. In FCA 9, the bottom-up approach was introduced as their practice, 18 though not codified as a Tariff requirement, and one that the ISO would supposedly couple with 19 a cross-check against publicly available data. In the IMM's testimony included in the filing of 20 the FCA 9 ORTPs, it stated that "all cost components [of the bottom up analysis] were crosscompared against other publicly available datasets for reasonableness."48 Thus, an expectation 21

⁴⁷ ISO-NE Tariff § III.A.21.1.2(b).

⁴⁸ ISO New England Inc., Joint Testimony of David Naughton & Scott Hodgdon, Docket No. ER14-616, at 15 (Dec. 13, 2013).

was set that the bottom-up approach would be subject to this cross-check. That process did not occur in the FCA 16 ORTP recalculation process. In other words, neither the ISO nor its consultants have in the FCA 16 ORTP recalculation process provided evidence of any such cost benchmarking against publicly available data sets, while dismissing all publicly available data sets that have been presented to them. Without this benchmarking, the ISO's method seems both inconsistent with its Commission-accepted practice established in FCA 9, and less accurate than the method used to develop the NEPOOL Alternative for the offshore wind ORTP.

8 Further, a bottom-up cost estimate does not necessarily result in a higher level of 9 accuracy than alternative cost estimate methodologies. Errors can be present in any type of 10 estimate. What verifies that a reasonable level of accuracy has been obtained in any cost 11 estimation process is when multiple methods converge. The literature review we have performed shows a high level of convergence regarding offshore wind cost expectations that have been 12 13 developed in a variety of ways by a variety of sources. Though uncertainty exists in any 14 individual estimate or methodology, the preponderance of publicly available data points to a 15 fairly narrow range of offshore wind cost expectations of about \$2,500/kW to \$4,000/kW 16 (2019\$). The NEPOOL proposed cost assumption of \$3,326/kW (2019\$) falls squarely in the 17 middle of this expected range of costs while the ISO's proposed assumption of \$5,358/kW falls 18 outside of the range cited by any source for a somewhat comparable project with a commercial 19 operation date within seven years of the reference ORTP project.

IV.6. Including a thirty percent ITC is just and reasonable.

2 Q: Please describe why a thirty percent ITC was included in the ORTP for offshore 3 wind for FCA 16.

A: Originally, the ISO ORTP Proposal assumed that the reference ORTP unit, which is
assumed to start physical construction in early 2021 and begin commercial operation in early
2025 would not receive any value from the ITC. However, after the Consolidated Appropriations
Act, 2021 (the "Act") was signed into law on December 27, 2020,⁴⁹ ISO revised its proposal to
include 30% ITC for the offshore wind project.

9 Originally, NEPOOL supported an ITC value of 18% for offshore wind projects, 10 reflecting industry practice and expectations in relation to the tax law prior to the Act. After the 11 Act was signed into law, NEPOOL held two special Markets Committee meetings to discuss the 12 implications of the change in Tax law on the ORTP. After these discussion, NEPOOL supported 13 an ORTP value for offshore wind that also reflects a 30% ITC value, which is in line with the 14 new law⁵⁰ and prevailing industry expectations.

15 V. PTC/ITC ANNUAL UPDATE

1

16 **Q:** Please describe the ITC and PTC.

A: The federal renewable electricity PTC, available under Section 45 of the Internal
Revenue Code ("IRC"), is an inflation-adjusted per-kilowatt-hour tax credit for electricity
generated by qualified energy resources in its first ten years of operation. The full inflation-

⁴⁹ Consolidated Appropriations Act, Pub. L. No. 116-260, 134 Stat. 1182 (2020).

⁵⁰ Under the Act, offshore wind projects that begin construction any time between January 1, 2017 and December 31, 2025 qualify for a 30% ITC. *See id.*

adjusted value of the tax credit is \$0.025 per kilowatt-hour in 2020\$.⁵¹ The Business Energy Investment Tax Credit, available under Section 48 of the IRC, is a federal income tax credit for capital investments in renewable energy projects. The full value of this one-time credit is thirty percent of the dollar amount of the investment in the renewable energy property and is earned when the equipment is placed into service.

For solar projects, under current tax law, the level of ITC a project is eligible for changes based on the date the project begins construction and the ability of the project to show continuity through commercial operation. As set forth in the Act, solar projects are eligible for the levels of ITC shown in the table below. The table shows the date before which a project must start construction, the date four years later by which it must commence operating in order to automatically meet the continuity requirement, and the corresponding level of ITC eligibility.

Start of Construction	For 4-year Continuity Safe Harbor, Reach Commercial Operation By	ITC Eligibility as of December 2020
Before January 1, 2021	December 31, 2024	26%
Before January 1, 2022	December 31, 2025	26%
Before January 1, 2023	December 31, 2026	26%
Before January 1, 2024	December 31, 2027	22%
January 1, 2024 or after	4 th calendar year after start	10%

PTC and ITC policies are important considerations when developing solar and other renewable energy projects. Whether a project has access to these programs has a significant impact on a project's economics, so much so that access to PTC or ITC could be a deciding factor in whether a project is viable or not.

⁵¹ I.R.S., Credit for Renewable Energy Production, Refined Coal Production, and Indian Coal Production, and Publication of Inflation Adjustment Factors and Reference Prices for Calendar Year 2020 (May 13, 2020), <u>https://www.federalregister.gov/documents/2020/05/13/2020-10273/credit-for-renewable-electricity-production-refined-coal-production-and-indian-coal-production-and#:~:text=Inflation%20Adjustment%20Factors%3A%20The%20inflation,and%20refined%20coal%20i s%201.6687.</u>

Q: The NEPOOL Alternative would require the ITC input assumption for solar
 resources to be adjusted as part of the ORTP annual update process for FCAs 17 and 18.
 Why is it appropriate to make such an adjustment?

A: For FCA 16, NEPOOL supported the use of a 26% ITC value for solar resources,
identical to the assumption used by ISO. However, because the ITC eligibility steps down in
subsequent years, I believe it is appropriate that future ORTPs reflect this step-down provision.

7 Therefore, like the ISO's Proposal, the NEPOOL proposal contains recommended values 8 for the ITC that should be assumed for the calculation of the ORTP for solar resources in FCAs 9 17 and 18. These values, which differ from the values in the ISO proposal, were recommended in 10 order to reflect the ITC levels that a rational, profit-maximizing developer would expect to 11 achieve based upon the current tax law.

Additionally, the NEPOOL Alternative would update these solar ITC values, and PTC or ITC values for other resources as applicable, should there be further changes to these provisions of the tax law prior to the annual ORTP updates in these future years. This part of the NEPOOL Alternative is discussed later in this testimony.

Q: What level of ITC does the NEPOOL Alternative use for the calculation of the ORTP for solar projects for FCAs 17 and 18 under the current tax law?

A: The NEPOOL Alternative uses the assumption that a solar project would be eligible for a 26% ITC for FCA 17 and a 22% ITC for FCA 18 under the current tax law. These values are consistent with the eligibility requirements set forth in the Internal Revenue Code Section 48⁵² and with developer expectations for projects that would participate as new capacity resources in FCAs 17 and 18.

⁵² 26 U.S.C. § 48.

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Attachment N-1b – Testimony of Abigail Krich

Q: How would a solar project meet the appropriate start of construction and continuity
 requirements to achieve these levels of ITC for FCAs 17 and 18?

A: To be eligible to claim the 26% ITC for FCA 17, a solar project must demonstrate start of construction by the end of calendar year 2022. According to IRS Notice 2013-29, this can be demonstrated in one of two ways.⁵³ First, the solar project could begin physical work of a significant nature in 2022. Alternatively, the solar project may incur 5% of total eligible costs in that year to meet the beginning of construction safe harbor.

8 Next, the project must commence commercial operation by the end of the fourth calendar 9 year after it begins construction to meet the continuity safe harbor requirement. Projects may 10 demonstrate continuity for periods longer than four year with the appropriate documentation, but 11 based on the development cycle for most solar developers, solar projects are not often developed 12 on timelines longer than this.

This means that, utilizing the four year safe harbor for continuity, the latest a project could reach commercial operation and qualify for 26% ITC is the end of 2026. The FCA 17 Capacity Commitment Period begins in June of 2026. Projects that have been awarded Capacity Supply Obligations for FCA 17 are expected to reach COD prior to this date. FCA 17 projects therefor fall squarely within the allowable timeframe for the 26% ITC eligibility.

It is only reasonable to assume that a developer would seek to maximize its profits. This includes weighing the costs and benefits of spending a small amount of money earlier than might otherwise be necessary in order to meet the safe harbor requirements to achieve the highest possible tax benefit under the current tax law. When the benefits of the increased ITC outweigh the added cost and risk of spending a portion of the project's budget sooner, as is the case for

⁵³ I.R.S., Notice 2013-29: Beginning of Const. for Purposes of the Renewable Electricity Production Tax Credit and Energy Investment Tax Credit, at 2 (2013), <u>https://www.irs.gov/pub/irs-drop/n-13-29.pdf</u>.

solar projects, the prudent approach for a developer is to take the necessary actions to lock in the
higher ITC value. Therefore, for a solar project that is expected to be a New Capacity Resource
for FCA 17 (reaching COD prior to June 2026), the project would be expected to start
construction four calendar years prior, in 2022, to take advantage of the 26% ITC.

5 The same logic applies for FCA 18 with dates and eligibility shifted one year into the 6 future: a New Capacity Resource for FCA 18 would need to reach commercial operation before 7 June 2027, which means it would need to start construction four calendar years prior (in 2023) in 8 order to meet the safe harbor requirements for a 22% ITC.

9 Q: Is it reasonable for a solar developer to begin construction four years prior to when 10 the project is expected to reach commercial operation? If so, how would a project do so?

11 Yes, it is reasonable for a solar project to begin construction, as set forth in IRS A: guidance,⁵⁴ four years prior to reaching its commercial operation date. As I noted earlier, a solar 12 13 project can meet the start of construction for purposes of ITC qualification in one of two ways: 14 the Physical Work Test (i.e., commencing physical work of a significant nature, such as on-site 15 construction activities or manufacturing of significant components specific to a project like a 16 transformer) or the 5% Safe Harbor (i.e., incurring at least 5% of the total cost of the eligible 17 basis of the property, such as purchasing a portion of the solar modules for the project). While 18 some developers may choose to meet the Physical Work Test, many solar developers choose to 19 incur 5% of their costs as the risk of not being able to use purchased equipment is low and the 20 tax benefit is high.

21 Many solar developers choose to purchase a portion of their equipment years in advance 22 of when they expect to use it because it allows them to take advantage of higher ITC levels, a

⁵⁴ I.R.S., Notice 2021-05: Beginning of Const. for Sections 45 & 48; Extension of Continuity Safe Harbor for Offshore Projects & Fed. Land Projects, at 4 (2021), <u>https://www.irs.gov/pub/irs-drop/n-21-05.pdf</u>.

1 benefit that is far higher than the carrying cost of holding that equipment for a number of years 2 or the risk of the equipment losing value should the project fail to reach commercial operation. 3 Due to the modular nature of solar photovoltaic generators, much of the equipment used in the 4 construction of a solar generator is non-site specific (e.g., solar panels, inverters, and even some 5 transformers). As a result, if a project were to be unsuccessful after a developer purchased a 6 portion of its equipment, the developer would be able to redirect this equipment to a different 7 project. Further, due to the original purchase date of the equipment, it may be possible for the 8 project to which this equipment is redirected to take advantage of the higher ITC value, as the 9 equipment could establish an earlier start of construction date for the new project. Thus, because 10 the pre-purchased equipment would be expected to retain its own physical value as well as the 11 value of the ITC safe harbor, even if a specific project fails, the value of the equipment 12 purchased for purposes of safe harboring remains high. This nearly eliminates the risk of loss 13 that would normally be associated with purchasing generating equipment in advance, even if the 14 project development risk is high.

The reward for safe harboring large quantities of equipment for a solar developer's pipeline of future projects outweighs the risk of incurring costs earlier than otherwise necessary, and therefore is common industry practice. Because ORTPs are supposed to reflect prevailing market expectations, it would be unreasonable to not include this practice and the higher ITC values in the calculation of the ORTPs for FCAs 17 and 18.

Q: The ISO has assumed that a developer would not use the full four years to safe harbor and instead wait until after the results of the FCA before making financial commitments to the project. This resulted in their proposal to update the ITC for solar projects for FCA 17 to 22% and for FCA 18 to 10%. Is this a reasonable assumption?

A: No, this is not a reasonable assumption. By delaying the start of construction for purposes of ITC eligibility by 5.5 weeks (such that the first investment in the solar project would occur in mid-February after the auction rather in December prior to the auction), a solar developer would be giving up a tax benefit equal to 4% of its total project cost in FCA 17 and 12% in FCA 18.

9 The solar ORTP value in the NEPOOL Alternative is \$0.000/kW-month (this is true even 10 with the FCA 18 ITC assumption of 22%). This indicates that the solar project does not rely on 11 any revenue from the capacity market to be financially viable. Clearing in the FCA is, therefore, 12 not a determining factor in a developer's decision about whether or when to begin investing in a 13 project.

14 Even for the ISO Proposal, which includes a solar ORTP of \$1.381/kW-month, indicating 15 that solar projects would require a small amount of FCM revenue to be financially viable, it 16 would not be reasonable to expect a solar developer to wait until clearing in the FCA before making the small at-risk expenditure required to safe harbor their project. As described earlier, 17 18 the risk involved with such an expenditure is minimal given the ease with which the modular 19 solar equipment can be used by another project should the project in question fail as well as the 20 added value embedded in such equipment related to the ability to obtain a higher ITC value on 21 another project that was not already safe harbored.

Waiting only a short period of time for the results of the FCA in order to make a small financial commitment is unreasonable when there are significant tax benefits to be gained by
investing slightly earlier and little risk of loss associated with doing so. Giving up tax benefits
that a project is eligible to receive is not a rational decision for a profit maximizing developer
and will result in an ORTP that does not reflect the expectations of solar developers.

Q: The NEPOOL Alternative includes a proposal to require the ISO to annually adjust
ORTPs in advance of FCAs 17 and 18 by including PTC and ITC inputs into the capital
budgeting model that reflect the most current tax law regarding these credits. Why is it
appropriate to make such adjustments?

A: PTC/ITC policies can have a significant effect on a project's economics. The December 2020 tax law change that increased an FCA 16 solar project's ITC value from 10% to 26% reduced the ISO's calculated solar ORTP value from \$10.714/kW-month to \$1.381/kW-month. A rational developer will take advantage of these programs when they are available. Therefore, PTC/ITC laws set commercial expectations for these types of projects and must be appropriately reflected in the ORTP model.

The previous responses regarded updating solar ITC levels for FCAs 17 and 18 in accordance with tax law as it stands today. However, given that this tax law could very well change again within the next two years, I believe that the ITC/PTC levels in the ISO's model should reflect the tax law at the time of the annual update, not at the time of the full recalculation.

19 This piece of the NEPOOL Proposal provides the Tariff language to allow ISO to reflect 20 in its model the current tax law at the time of the update. This will ensure that the ORTPs reflect 21 the most current expectations with regards to tax law and ensure that they do not reflect old laws 22 that are no longer in effect. This is a discrete assumption that can be determined clearly and has

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an outsized impact on the final ORTP value, making it appropriate to include in the annual
 update process.

3 Q: How frequently do PTC/ITC policies change?

4 A: PTC/ITC policies have historically changed more frequently than the ISO's full 5 recalculation of the ORTPs. In just the last eight years, PTC policy has changed six times (in 2013, 2014, 2015, 2018, 2019, and 2020)⁵⁵ whereas the ISO has performed a full ORTP 6 7 recalculation only three times (in 2013 for FCA 9, in 2016 for FCA 12, and in 2020/2021 for 8 FCA 16). Most recently, the Act extended the PTC and ITC eligibility for certain resources. It is 9 unknown whether this policy will change in the future but having a mechanism to capture these 10 changes in the default ORTP is important in setting a value that is representative of commercial 11 expectations.

12 Q: What has the ISO stated as to why it does not support updating the ITC/PTC?

A: The ISO's stated reasons for resisting automatically including such adjustments are that to do so would involve a complicated exercise in interpretation of tax law and that a single financial parameter should not be updated in isolation.⁵⁶ They said it would therefore be preferable, should tax law change significantly in the future, to make Tariff changes on an ad hoc basis to revise the ITC assumption for FCAs 17 and/or 18 or else address the tax law change in the individual offer floor price review process until a full ORTP recalculation is done for FCA 19.⁵⁷

⁵⁵ Cong. Research Serv., *The Renewable Electricity Production Tax Credit: In Brief* (Apr. 29, 2020), <u>https://fas.org/sgp/crs/misc/R43453.pdf</u> ("CRS Report").

⁵⁶ See Karl Mem. at 3 (page 253 of the PDF).

⁵⁷ See generally id.

1 Q: How

How do you respond to ISO's reasoning?

2 The ISO's reasoning is strained. It stated that it is not comfortable adjudicating tax A: 3 matters as part of the annual update process due to the potential complexity of appropriately applying tax law.⁵⁸ However, not addressing tax law changes in the annual update process in no 4 5 way avoids the need for the ISO to determine appropriate application of tax law. If the annual 6 update process does not reflect the change in law, and if the ISO does not make Tariff changes to 7 address the tax law change, then the ISO would still need to determine the appropriate application of any revised tax law for purposes of the individual resource offer floor price 8 9 review. There is no way to avoid the need for the ISO to determine appropriate application of 10 any such revised tax law, it is only a question of which process the ISO uses to recognize this 11 change. The most efficient, effective, and transparent process for this is the annual update.

12 The ISO's development of the ORTPs for FCA 16 has shown that the PTC/ITC 13 assumption can in fact be updated in isolation. Over the course of the ORTP development process, the ISO published various versions of their ORTP model that contained ITC 14 assumptions of zero, eighteen, and thirty percent for offshore wind.⁵⁹ All other financial 15 16 assumptions (e.g., weighted average cost of capital, debt-to-equity ratio, cost of debt, and cost of 17 equity) are consistent across the ISO's ORTP models with varying ITC assumptions, as well as 18 across all ORTP technologies even though some technologies are able to take advantage of the 19 PTC/ITC while others are not. Thus, this leads us to believe that ITC was not a factor in

⁵⁸ See id.

⁵⁹ Cell L21 of the Assumptions tab of the ORTP model provided to the Markets Committee at its September 8–10, 2020 meeting shows an eighteen percent ITC assumption for offshore wind. File name "a_6_a_iii_dcf_model_revision_2" is within the zip file located at the following link: <u>https://www.iso-ne.com/static-assets/documents/2020/09/a0_mc_meeting_materials_9th_set.zip</u>.

determining the other financial assumptions in the ISO's ORTP model and it is in fact reasonable
 to update this single parameter in isolation.

3 To update the PTC/ITC assumption would be a simple update in ISO-NE's model. To 4 update the PTC/ITC value, one would need to determine the appropriate PTC and ITC 5 percentages for the applicable year from the most recent version of the federal tax code and plug 6 them into the ISO's model for the appropriate technologies, as CEA has done for FCA 16. 7 Should ISO-NE feel that there is need for input from tax or financial experts to determine the 8 appropriate PTC and ITC percentages, it would not be unreasonable for the ISO to seek that 9 guidance for purposes of the annual update. Surely, the same guidance would be needed for the 10 individual offer floor price reviews performed shortly thereafter.

11 Finally, the timing of PTC/ITC changes has historically not lent itself to timely Tariff 12 updates. To illustrate this, the PTC/ITC was changed on December 20, 2019 and the subsequent annual update for FCA 15 was completed on March 6, 2020.⁶⁰ It would not have been possible, 13 14 except under exigent circumstances, which this would not have been, for the Tariff to be updated 15 to reflect the change in tax law in time for the FCA 15 annual update. This was not a one-off 16 occurrence. Rather, it was representative of typical timing. The PTC/ITC tax law updates have most commonly been made close to the end of the year⁶¹ and the ORTP annual updates have 17 18 been performed in February or March, in advance of the start of the new capacity qualification process.⁶² 19

⁶⁰ ISO New England Inc., Summary of 2024–2025 ORTPs (2024\$), <u>https://www.iso-ne.com/static-assets/documents/2020/03/2024-2025-ccp-forward-capacity-auction-15-iso-offer-review-trigger-price-update.xlsx</u>.

⁶¹ CRS Report at 4–5.

⁶² See, e.g., Search Results for ORTP Annual Updates: <u>https://www.iso-ne.com/search?file-type=XLS&file-type=XLS&file-type=CSV&file-type=xls&file-type=xls&file-type=type=csv&sort=publish_date_dt.desc&query=offer%20review%20trigger%20price%20update.</u>

1 VI. BATTERY ORTP PROPOSAL

2 Q: How does the NEPOOL Alternative's Battery ORTP Proposal compare to the ISO's 3 proposal?

A: The Battery ORTP Proposal is \$0.311/kW-month lower than the battery ORTP included
in the ISO's proposal. This difference is a result of the Energy and Ancillary Service ("E&AS")
revenue assumption used in the model to calculate the ORTP for the battery. The NEPOOL
Alternative's battery ORTP is \$2.601/kW-month and the ISO's battery ORTP is \$2.912/kWmonth.

9 Q: What is the basis for the number in the NEPOOL Alternative's Battery ORTP
10 Proposal?

11 A: The NEPOOL Alternative's energy storage ORTP was derived using the same ORTP 12 model as the ISO's. The NEPOOL Alternative, however, uses a different assumption regarding 13 the E&AS revenue the reference unit receives. The E&AS revenues are the largest component of 14 a battery's overall non-capacity revenues (other revenue streams include PFP and scarcity 15 pricing).

In their proposal, the ISO relies on a dispatch model developed by CEA for their E&AS revenue assumption.⁶³ The NEPOOL Alternative relies on a dispatch model developed by the Massachusetts Attorney General's Office ("AGO") for the alternative E&AS revenue assumption.⁶⁴ The only assumption that differs between the NEPOOL Alternative and the ISO proposal is the E&AS revenues the battery receives from the energy and ancillary services markets.

⁶³ File name "Battery_ORTPdispatch_2020.09.30wFRM.xlsx" available in the zip file at this link from the October 8–10 MC materials: <u>https://www.iso-ne.com/static-assets/documents/2020/10/a5b_ortp_models.zip</u>.

⁶⁴ See AGO Dispatch Model, <u>https://www.iso-ne.com/static-assets/documents/2020/11/a4_b_xii_ma_ago_alternative_eas_model.zip.</u>

- VI.1. CEA's suboptimal battery dispatch model leaves "money on the table" as
 compared to the model developed by the AGO.
- 3

Q: Please describe the CEA battery dispatch model.

A: The CEA battery dispatch model utilizes simplified logic to determine when to charge and discharge the Energy Storage Device in the Day Ahead Energy Market ("DAM") and Real Time Energy Market ("RTM") and to tally the resulting amount of E&AS revenue earned. This model was built using basic formulas in an Excel spreadsheet. It discharges the Energy Storage Device in the DAM and RTM based on a threshold price, re-charges at a fixed time of day, and then participates in regulation and reserve markets in times when it is neither charging nor discharging.

In the DAM, the Energy Storage Device discharges during the first two hours of each day in which the Locational Marginal Price ("LMP") for energy reaches a threshold price level equal to the 95th percentile of DAM LMPs for the year. The Energy Storage Device re-charges in hours ending ("HE") 3–5 every day in which it does not start fully charged.

In the CEA dispatch model, the Energy Storage Device automatically buys back its full Day-Ahead ("DA") schedule in Real-Time ("RT"), which means the Energy Storage Device's DA and RT market participation are entirely independent of one another and the dispatch strategy in one has no impact on the other.

In the RTM, the Energy Storage Device charges and discharges using identical logic as in the DAM but using RTM prices to determine whether and when to discharge. In hours when the Energy Storage Device has a positive state of charge and is neither charging nor discharging, the Energy Storage Device provides reserves.

In all hours, the Energy Storage device also sets aside eleven percent of its capacity to provide Regulation services. These revenues were calculated outside of CEA's battery dispatch model by the ISO. The Energy Storage Device provides 16.5 MW of regulation service in all hours compensated at a net average payment rate of \$21.26/MWh, resulting in \$3,041,936 annually (2019\$).

An example of the Energy Storage Device dispatch using this very simple methodology is shown in the stylized figure below, which was created from data in the CEA battery dispatch model.⁶⁵ The solid orange trace is the RT LMP at the location of the Energy Storage Device. The dashed orange trace is the Real Time offer threshold for 2017. The red bars are hours in which the Energy Storage Device charges, and the green bars are hours in which the Energy Storage Device discharges. The Energy Storage Device does not necessarily charge or discharge its full capability in any one of the hours highlighted below.



September 27, 2017 - ISO's RT Dispatch

⁶⁵ ISO New England Inc., Battery ORTP dispatch with FRM (Nov. 24, 2020), <u>https://www.iso-ne.com/static-assets/documents/2020/11/a4_a_i_battery_dispatch_ortp_version_posted_nov_24.xlsx</u>.

13

Under the CEA dispatch strategy, dispatch is not optimized to capture revenues that could be earned in the energy market at the highest priced hours of the day. As seen in the figure above, the Energy Storage device does not discharge at higher priced hours (HE 16–22) because thas already discharged in the first two hours (HE 14–15) that the RT LMP exceeded the ISO's threshold. Put differently, the dispatch strategy is myopic and does not account for any intertemporal opportunity costs.

By observing the DA clearing prices for this operating day, illustrated in the figure below, a rational operator would assume that prices would continue to rise after the two hours in which the battery discharged under the CEA model. RT prices are strongly correlated with DA prices. If the CEA model were to look at DA prices ahead of its RT dispatch, then it would be able to more cleverly dispatch the Energy Storage Device in RT to capture times when prices are expected to peak.

For example, the solid blue trace on the figure below shows the DA LMP at the location of the Energy Storage Device. DA market prices continued to rise after HE 14–15. The data for this figure also came directly from CEA's battery dispatch model and correspond to the same operating day as the figure above. This information about DA clearing prices would be available to the Energy Storage Device prior to scheduling its RT dispatch.



September 27, 2017 - Day Ahead Prices

In addition to losing the ability to discharge at higher prices in the RTM, the CEA model gives no consideration for the cross-product lost opportunity cost associated with losing the ability to provide reserves by discharging for energy earlier in the day. It is possible for the Energy Storage Device to earn more total E&AS revenue by waiting to discharge some or all of its energy in the RTM until later in the day and by providing reserves in those hours before the Energy Storage Device chooses to discharge. By discharging to a zero state of charge early in the day, the Energy Storage Device loses the ability to provide reserves for a longer period.

In addition to the CEA model's failure to capture intertemporal and cross-product 8 9 opportunity costs, the CEA battery dispatch model also recharges the battery in an overly 10 simplistic manner. Irrespective of expected prices, the Energy Storage Device charges over a 11 fixed period every day no matter what the prices are in those hours. While there may be historic 12 precedent that HE 3–5 are the lowest price hours on average, there is no guarantee that they are 13 the lowest price hours on any given day. The Energy Storage Device has no flexibility under the 14 CEA battery dispatch model to deviate from these hours if prices rise. In fact, the Energy Storage 15 Device under the CEA battery dispatch has no ability to respond to market conditions in any 16 aspect of its market participation.

17 Q: Please describe the AGO's dispatch model.

A: The AGO dispatch model calculates revenue streams for the Real Time Energy, Reserves, and Regulation Markets for the reference unit. This model is built using a linear programming optimization algorithm to schedule the Energy Storage Device in the RTM using available DAM LMPs and a fixed assumption regarding the opportunity cost of losing the ability to participate in the reserve market by discharging for energy. By explicitly accounting for crossproduct and intertemporal opportunity costs, the AGO model creates a more realistic Energy

1 Storage Device dispatch strategy. Importantly, the AGO model does not require any foresight 2 beyond known prices from the already-run DAM. The benefits of the optimization framework 3 are illustratively shown in the figure below, which depicts the dispatch of the Energy Storage 4 Device, on the same day as was shown above, under the AGO's dispatch methodology in the 5 Real Time Energy Market.

6 The Energy Storage Device is scheduled to discharge in RT in hours when the DA LMP 7 is high and is scheduled to charge in RT in hours when the DA LMP is low. Note that the AGO 8 models the operation of the storage device in the real-time market only, with the storage device 9 being paid the real-time price, but its dispatch decision-making is done according to day-ahead 10 prices. The AGO published its model, a report outlining its methodology, and its results with the 11 Markets Committee materials in November.⁶⁶



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Reserve and regulation payments under AGO's dispatch strategy were calculated in a similar manner to how they were calculated in CEA's dispatch model. Like CEA, the AGO assumes that the storage device participates in the Forward Reserve Market. In hours when the Energy Storage Device was neither charging nor discharging, it provides reserves based on its

⁶⁶ See Revenue for Energy Storage Participating in ISO-NE Energy and Reserves Markets: Alternative ORTP EAS Offset Estimates, Massachusetts Attorney General's Office (Nov. 2020), file name "a4_b_xii_ma_ago_memo_re_alternative_eas_energy_storage" at <u>https://www.iso-ne.com/static-assets/documents/2020/11/a00_meeting_materials_5th_set.zip</u>.

state of charge, compensated at the Forward Reserve Market or Ten-Minute Spinning Reserve rate, depending on the time-of-day. These reserve payments made up the largest portion of the Energy Storage Device's E&AS revenue stack. One reason the AGO approach earns more reserve revenue than a battery using CEA's technique is its tendency to recharge soon after being discharged for energy, rather than sitting empty and idle until the early morning hours. This strategy allows it to earn additional reserve revenue on these high-priced days.

As in the ISO's proposal, the Energy Storage Device sets aside eleven percent of its capacity to provide regulation services. The Energy Storage device was compensated in all hours for the 16.5 MW of regulation capacity at a net average rate of \$21.26/MWh, resulting in the identical regulation payment for the Energy Storage Device as was calculated for the ISO's proposal.

Under the methodology described above, the AGO calculated that the reference Energy
Storage Device could earn \$8,812,453 annually from the RT Energy, Reserve, and Regulation
markets, compared to \$8,252,678 in the CEA model, a 6.8 percent increase.

Q: Does the AGO's dispatch methodology require additional information (e.g., price
 forecasts) not used in the ISO's dispatch methodology?

A: The AGO's dispatch methodology does not require additional information when compared to ISO's dispatch methodology but does use the available DA price information when scheduling the unit in RT. The additional E&AS revenue the reference unit receives in the NEPOOL Alternative is solely due to the decision to use available Day Ahead LMPs to determine when to charge and discharge the unit in Real Time and to optimize that Real Time charging and discharging process. The AGO's dispatch methodology does not require sophisticated price forecasts, it simply uses the DA LMP as a forecast of RTM prices. Under the

AGO's dispatch strategy, the Energy Storage device has no foresight into future Real Time LMPs; it only uses information related to the DA LMP, which is available to the unit prior the time when it would need to schedule its energy in Real Time. The reference unit has the same information at the same time in both the NEPOOL Alternative and the ISO ORTP Proposal. The reference unit earns more revenue under the NEPOOL Alternative simply due to using this available information to make more profitable decisions about how to operate the unit.

Q: Does the AGO's dispatch methodology affect any of the other assumptions in the ISO's ORTP model?

9 A: The AGO's dispatch methodology does not affect any of the other assumptions in ISO's 10 ORTP model. Its dispatch strategy implements the same technology as CEA and therefore would 11 not impact any of the capital cost or financing assumptions used in the ORTP model. The AGO 12 dispatch strategy would not affect the number of scarcity hours at criteria, PPR, average actual 13 performance, reserve constraint penalty factor, or average balancing ratio assumed for the reference unit as those were all calculated by CEA and MM independently of the dispatch 14 15 methodology. Therefore, the Energy Storage Device would receive the same PFP and Scarcity 16 revenues under both the ISO Proposal and NEPOOL Alternative. The only assumption that is 17 different between the NEPOOL Alternative and ISO's proposal is the E&AS revenues the 18 Energy Storage Device receives from the Real-Time markets.

19 Q: Does the AGO dispatch methodology result in more frequent cycling of the battery 20 that would be expected to increase operations and maintenance costs?

A: The ISO has asserted that the Operations and Maintenance ("O&M") costs of the Energy
Storage Device could potentially increase under the AGO's dispatch methodology because the
Energy Storage Device cycles more frequently. The O&M assumption used in the ISO's ORTP

model for the Energy Storage Device was developed prior to when the ISO developed its dispatch strategy. There was no discussion by the ISO or its consultants during the NEPOOL stakeholder process, nor in CEA's Final Report, that the O&M figure developed by CEA in consultation with MM was related to the specific cycling frequency of the reference unit in CEA's dispatch model.

6 Moreover, in June 2019, NREL published a paper on cost projections for Utility-Scale 7 storage.⁶⁷ For its analysis, it conducted a literature review of fixed O&M costs and selected a 8 value to use in its Annual Technology Baseline report. In this process, NREL chose a value that 9 would "counteract degradation such that the system will be able to perform at rated capacity throughout its lifetime."⁶⁸ Using this value in its Annual Technology Baseline report.⁶⁹ NREL 10 11 determined the O&M cost for a 2-hour battery in 2025 was approximately \$22/kW-month 12 (2025\$), which is in line with CEA's assumption of \$24.41/kW-month (2025\$). As part of this 13 analysis, NREL states it assumed the battery with this O&M cost would cycle once per day. 14 Furthermore, NREL found no need to change its one-cycle per day assumption, which has "long been [its] assumption" for cycling frequency.⁷⁰ 15 16

17

Similar comparisons between O&M costs and cycling can be done with other publicly available data, including Lazard⁷¹ and EIA.⁷² From those comparisons the same conclusion can

 ⁶⁷ Wesley Cole & A. Will Frazier, *Cost Projections for Utility-Scale Battery Storage*, Nat'l Renewable Energy Lab. (Jan. 2019), <u>https://www.nrel.gov/docs/fy19osti/73222.pdf</u> ("NREL Tech. Report").
 ⁶⁸ *Id.* at 10.

⁶⁹ Nat'l Renewable Energy Lab., 2020 Annual Technology Baseline Report, <u>https://atb.nrel.gov/electricity/2020/about.php</u>.

⁷⁰ NREL Tech. Report at 11.

⁷¹ Lazard's Levelized Cost of Storage Analysis – Version 6.0, Lazard, https://www.lazard.com/media/451418/lazards-levelized-cost-of-storage-version-60.pdf.

⁷² EIA Report at 18-6–18-7, 19-3–19-4.

be drawn: O&M costs for Energy Storage Devices in the range of CEA's estimate for O&M
 correspond to the industry norm of one cycle per day.

Because the CEA O&M number reflects the general industry expectation and the general industry expectation is a unit that cycles once per day, the O&M figure developed by CEA represents a reasonable expectation for O&M for the technology operating around one cycle per day.

Both under the ISO ORTP Proposal and Battery ORTP Proposal, the Energy Storage Device cycles on average less than once a day. Cycling frequencies less than once a day fall within normal operation for a utility-scale Energy Storage Device. For this reason, CEA's estimated O&M value, which aligns with recent literature, is appropriate for the reference unit in the Battery ORTP Proposal.

12 VI.2. The Battery ORTP Proposal takes a reasonable approach to calculate E&AS 13 revenues.

Q: The CEA model includes E&AS revenues from both the DAM and RTM while the
AGO model only calculates RTM revenues. Are DAM revenues factored into the Battery
ORTP Proposal?

A: Yes, the NEPOOL Alternative includes revenues from both the DAM and RTM, just like
the ISO proposal. The NEPOOL Alternative made no modifications to the DA revenue stream
used in the ISO proposal. The NEPOOL Alternative modified only the RT revenue streams,
using the revenues derived with the AGO optimization model.

DA and RT market participation are decoupled in both the ISO's proposal and the NEPOOL Alternative, which allowed the use of CEA's model for the former and the AGO model for the latter. The way CEA built its model for all ORTP and CONE units, DA scheduling

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and RT dispatch decisions are made entirely independent of one another because the unit is
assumed to buy back its full DAM position in RT. The Battery ORTP Proposal did not propose
to alter this building block of the CEA model. CEA's dispatch model calculated that the
reference unit could earn \$36,303 annually in the DAM, and so does the Battery ORTP Proposal.

5 The CEA DAM dispatch strategy reflects the bare minimum DAM revenue that could be 6 expected by any competent energy storage operator. The Battery ORTP Proposal was not 7 intended to approximate what a particularly sophisticated energy storage operator would be able 8 to achieve, but rather to set a reasonable baseline for the minimum level of E&AS revenues that 9 any battery storage operator should expect to receive. In order to optimize DA market 10 participation, as the AGO model did in real time, one would either need a DAM price forecast or 11 would need to rely on the DAM clearing engine to optimize the limited available energy from the 12 Energy Storage Device. Given the modest revenues available in the energy markets, the Battery 13 ORTP Proposal did not attempt to develop such a price forecast or approximate the DAM 14 clearing engine optimization, which is slated to be revised in the coming years as part of Order 15 841 compliance and it is not yet known if the optimization option will remain available to 16 storage operators or, if so, what it may look like.

Q: How does the total E&AS revenue used to develop the Battery ORTP Proposal compare with that of the CEA model utilized in the ISO proposal and how does this impact the ORTP?

A: The figure below summarizes the four E&AS revenue streams used as an assumption in
 the ORTP model in both the ISO ORTP Proposal and the Battery ORTP Proposal. The
 NEPOOL-approved battery storage ORTP value was established using a total E&AS revenue

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- 1 assumption of \$8,848,756 annually and the ISO's proposal uses an E&AS revenue assumption of
- 2 \$8,288,981 annually.



Annual Revenue by Product (Millions, 2025\$)

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4 To calculate the NEPOOL-approved battery storage ORTP value, we substituted the ISO's 5 E&AS value seen in the figure above with the NEPOOL E&AS value seen in the figure above. 6 All other modeling assumptions were kept consistent and the model was re-run with the new 7 E&AS assumption. The E&AS revenue stream in the Battery ORTP Proposal is larger than the 8 E&AS revenue stream in the ISO Proposal because charging and discharging is optimized under 9 the Battery ORTP Proposal. The more non-capacity revenue the Energy Storage Device receives, 10 the less revenue it would need from the capacity market to make itself whole. Therefore, when 11 included in CEA's model to calculate the ORTP for the Energy Storage Device, the greater 12 E&AS revenue stream in the Battery ORTP Proposal results in a lower ORTP.

1

VI.3. Miscellaneous comments on Energy Storage Devices.

Q: Why is an optimization algorithm the preferable dispatch methodology for an Energy Storage Device?

A: Using a simplified, non-optimized dispatch model is not appropriate for modeling battery storage participation in the markets today, let alone during the Capacity Commitment Period associated with FCA 16. Energy Storage operators in the market today rely on far more sophisticated dispatch strategies than the one proposed by either ISO or NEPOOL. These strategies require complex price forecasting and optimization algorithms.

9 A competent and rational resource operator will do everything it can to maximize 10 revenue from the markets. Given the same information and technology, the reference unit under 11 the AGO's dispatch methodology was able to earn more revenue in the E&AS markets than 12 operating under ISO's methodology. A rational Energy Storage operator would not choose the 13 ISO's methodology of dispatch if it had the choice between the two.

Q: What is the history of modeling E&AS revenues for Energy Storage Devices concerning ORTPs and resource-specific offer floor prices?

A: While this is the first time the ISO has gone through the process of calculating a default ORTP for Energy Storage Devices, a market participant did submit a Protest to the Commission on the methodology the IMM used to estimate battery revenues concerning its FCA 14 resourcespecific offer floor price review.⁷³ The market participant alleged that the IMM's methodology for estimating E&AS revenues grossly underestimated the revenues an actual developer would expect to receive.

⁷³ See ISO New England Inc., Motion to Intervene and Protest by Able Grid Infrastructure Holding, LLC, Docket No. ER20-308 (filed Nov. 20, 2019).

1 In a motion to intervene in the informational filing, the External Market Monitor ("EMM") filed comments on the IMM's methodology for estimating battery revenues.⁷⁴ The 2 3 EMM asserted that the IMM's methodology was not fully using data that would be available to 4 the unit at the time of dispatch, just as the ISO is currently not taking advantage of information 5 available at the time of dispatch for the reference unit in the ORTP recalculation process, resulting in E&AS revenues that were "unreasonably low."⁷⁵ In its filing, the EMM discussed 6 7 three possible alternative dispatch methodologies to remedy the shortcoming, one of which 8 aligned closely with the methodology implemented by the AGO. In its description of this 9 methodology, which resulted in the lowest E&AS revenues of the three methodologies it 10 presented, the EMM explained, "given the limited sophistication of this approach, this represents 11 the minimum that an Energy Storage Resource could reasonably expect to receive in EAS net revenues."⁷⁶ 12

While the EMM's feedback and suggested alternative battery dispatch approaches were provided too late in the FCA 14 qualification process to be able to be fully considered in that qualification cycle, RENEW Northeast sought the opportunity to discuss and assist in improving the battery dispatch model to ensure better future outcomes.⁷⁷ The IMM stated that it welcomed such discussion with market participants.⁷⁸ That is precisely what RENEW attempted to do in the stakeholder process for this first battery ORTP calculation. RENEW raised concerns with the

⁷⁴ *ISO New England Inc.*, Motion to Intervene and Comments of the ISO-New England External Market Monitor, Docket No. ER20-308 (filed Nov. 12, 2019).

⁷⁵ *Id.* at 7.

⁷⁶ *Id*. at 6.

⁷⁷ *ISO New England, Inc.*, Protest and Comments of RENEW Northeast, Inc., Docket No. ER20-308, at 3–5 (filed Nov. 20, 2019).

⁷⁸ *ISO New England, Inc.*, Answer of the Internal Market Monitor of ISO New England, Inc. to Comments and Protests Filed in Response to the Informational Filing for the Fourteenth Forward Capacity Auction, Docket No. ER20-308, at 27 (filed Dec. 5, 2019).

overly simplistic and under-performing battery dispatch model proposed by the ISO in August, at
 the very first Markets Committee meeting it was introduced by the ISO. RENEW then brought
 forward a specific alternative modeling approach, discussing and refining it at the following
 three committee meetings.

5 Q: Do you think a developer could implement a dispatch methodology that earns more 6 revenue than what could be earned from methodology implemented in the Battery ORTP 7 Proposal?

8 Yes, a developer could certainly earn more revenue from the E&AS markets than A: 9 calculated by the AGO's dispatch methodology. As was done with the ISO's proposal, the 10 Battery ORTP Proposal offers transparency and understandability. The linear optimization 11 algorithm central to the AGO model is more sophisticated than the CEA model but still 12 maintains a level of understandability we thought was appropriate for this purpose. In exchange 13 for this level of transparency and understandability, the AGO's dispatch methodology may not 14 result in revenues as high as those seen by commercial operators; nevertheless, it provides a 15 more reasonable estimate of the baseline commercial expectations for the E&AS revenues for 16 Energy Storage Devices for the purpose of setting an ORTP.

17 VII. CONCLUSION

18 **Q:** Does this conclude your testimony?

A: Yes, except to summarize my conclusion that the NEPOOL Alternative provides for
ORTP values and a definition of Economic Life that are more realistic and closer to current
market expectations than the ISO's Proposal, for the reasons stated above.

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I declare, under the penalty of perjury, that the foregoing is true and correct to the best of my knowledge.

Oliquil J. Mill

Abigail Krich (Starr)

April 5, 2021

Appendix A to Attachment N-1b

APPENDIX A – OFFSHORE WIND CAPITAL COST LITERATURE REVIEW

The following appendix describes the publicly available data regarding offshore wind capital cost that was included in the Boreas Renewables literature review. While some of these reports rely on global data, Boreas took every step possible to appropriately compare the numbers in these reports with ISO's offshore wind reference unit and note where there were differences. In global reports, we reported the entire range of expectations unless otherwise noted. For example, where global reports differentiated between project location or size we excluded Asian projects and smaller projects, neither of which are comparable to the reference unit. Since the United States, including New England, should be included in these global cost projections for future years, we have no reason to believe that New England costs should fall outside these cited projected ranges. Even if the numbers in individual reports are not directly comparable to the project being analyzed in the ORTP calculation, we believe that this broad range of reports provides a reasonable benchmark for the full range of expectations for capital cost for comparable offshore wind developments. Because ISO's assumption does not fall even near this range for recent and future projects, we do not believe it represents a reasonable capital cost estimate for the reference offshore wind project in the FCA 16 ORTP calculation.

The following figure shows a summary of our research. A discussion of each source in this figure follows.



Publicly Available Offshore Wind Capital Cost Estimates

*Installed Capital Costs

†Overnight Capital Costs (excludes cost of interest during construction)

We do not believe that any of the data points on this figure are invalid or insufficient as CEA has claimed, though we would agree with CEA that some represent projects that are closer in comparability to the ORTP reference project than others. All organizations included in this figure are reputable and the costs they cite represent their findings on offshore wind capital costs. As with any estimation or data collection, there will be errors and uncertainty, but we do not believe this uncertainty invalidates this data. In each of the descriptions of the sources below we rank their suitability to be used as a benchmark for use in the ORTP recalculation process, based on the quality of the data source as well as the alignment or discrepancy of the underlying source assumptions with ISO's reference project. It is important to note how those discrepancies will impact the capital cost value reported by the source. Many of the reported discrepancies result in higher costs than those that would be expected for the particular New England project in question and correcting for those discrepancies would in fact lower the reported value rather than raise it. In the below descriptions we have indicated whether we believe the discrepancy would raise (R) or lower (L) the reported value with a letter next to the item.

Note: To adjust costs given in a different dollar year into 2019\$ we have used an assumption of 2% inflation across the board.

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150-ME 2020 (Keit)	<u>rence rechnology)</u>	_	Shaded bar	ids indicate	the year of	expecte	l'actual comr	nercial operation	a date		
		6,000	2016 2017	2018	2019	2020	2022	2023	2024	2025	2026
Specifications		\$ 5,000	1	-							
Title of Report	ORTP Recalculation for FCA 16	timate (20195		+	I	I	-		1	I.C	.
Publishing Year	2020	3,000 SE			1	I			Ŧ		-
Value (2019\$/kW)	\$5,358	O 2,000								-	
Range (2019\$/kW)	\$5,500-6,000	C 1,000									
Size (MW)	800	0		1. 14	41	1.1	0.0	040	0000	aann	1. 4. 0
Location	MA Lease Area		St Will	N. S. S.	1414	THE PARTY	ALL STREET	17, 84 B	STREET STREET	1. 10, 10, 10, 10, 10, 10, 10, 10, 10, 10,	CROOL ST
COD	2025				3, 18.	9. 9.	·9. · 1	The Call	Instanting	Tion	
Installed/Overnight	Overnight	_						0.	9. 9	0. 0.	
			Outdated	Available I Data	Data (Err	or Bars :	how cited n	unges) IS NI	O's Proposal EPOOL Alternati	ve	
Source	Link	4	Other 1S	Os				C	ost Trendline		
		*Installed G	Capital Cost	S.		Internet	during anno	(mation)			

ISO-NE 2020 (Reference Technology)

Publicly Available Offshore Wind Capital Cost Estimates

Description

As discussed at the MC meetings between June and November, the reference unit is an 800 MW project located in one of the Massachusetts offshore lease areas. The project consists of 67 12-MW turbines connected to an offshore substation with an AC-tie to an onshore interconnection at the existing Brayton Point substation. At the October 26 Markets Committee Meeting, ISO-NE's consultants CEA and Mott MacDonald (MM) reduced their proposed cost estimate from \$5,876/kW to \$5,358/kW. They provided the below cost breakdown, citing MM's confidential pricing database as the source of these numbers. While MM has provided some limited details regarding the assumed project design, they have not made available to the committee publicly available data that corroborates either their line item breakdown or the total capital cost.

	ISO's Estimate (2019\$kW)
Offshore Substation Platform	465,000
Install Submarine Export Cabling	583,000
Construct Landfall Transition Box	40,000
Interarray Cabling	242,250
Major Equipment	2,333,000
Project Contingency	183,163
Total EPC	3,846,413
Owner's Development Costs (Services)	192,321
Electrical Interconnection	55,000
Financing Fees (4% of costs financed w/debt)	153,857
Working Capital (1% of EPC)	38,464
Total Non-EPC	439,641
Total Cost (2019\$)	4,286,054
Total Cost (2019\$/kW)	5,358

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CEA and MM have argued that the primary reason their cost estimate is higher than other recent sources included in this literature review is due to differences in scope attributed to the project's financial ledger in different places, particularly related to the submarine export cabling. At the October 7 meeting, MM explained, for European projects, the utility oftentimes picks up the cost of the interconnection from shore to the substation platform which can be half of the total project cost (we would note that this is not the case in Germany or the UK). They described that they have adjusted global project costs to account for the specific scope required for the reference ORTP project, which is assumed to require a 60 mile submarine export cable. If the submarine export cable accounted for half of the ISO's estimated project cost, it might make sense as to why the total project cost was double the costs seen in Denmark where these costs are not borne by the project. However, as can be seen in the cost breakdown above, the submarine export cable comprises just fourteen percent of the total estimated cost of the ORTP reference project. Even if the export cabling were entirely eliminated from the project scope of work, the remaining \$4,629/kW would still be about thirty percent higher than the vast majority of sources in our literature review, which were clustered in the range of \$2,800 to \$3,500/kW. As such, it does not appear to us that the unique scope of work required for an offshore wind project in New England accounts for the disconnect between the ISO's proposed cost assumption and those in the remainder of this literature review.

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Publichy Available Offenore Wind Canital Cost Estimator

Cape white		rubicly Avanable Offshore wind Capital Cost Estimates
		Shaded bands indicate the year of expected/actual commercial operation date
Specifications		
Title of Report		\$5,000
Publishing Year		
Value (2019\$/kW)	\$5,898	3,000
Range (2019\$/kW)	N/A	
Size (MW)	468	Ê 1,000
Location	New England	
COD	2016	Can be the state of the state o
Installed/Overnight	Installed	To a the operation of t
		The second
Source	Link	Publicly Available Data (Error Bars show cited ranges) ISO's Proposal
		Outdated Data Outdated Data Other ISOs Cost Trendline
Description		*Installed Capital Costs †Ovemight Capital Costs (excludes cost of interest during construction)

Cano Wind

†Overnight Capital Costs (excludes cost of interest during construction)

The earliest data point we thought was important to include in this report was the widely reported cost figure for the Cape Wind project, \$2.6 billion. The Cape Wind project was a planned 468 MW project which results in a cost per kW of \$5,556/kW. The project was to be made up of 3.6 MW turbines and was supposed to be the Western Hemisphere's first offshore wind project. It entered the interconnection queue in 2001 and received power purchase agreements in 2010 and 2012 for the sale of energy, RECs, and capacity at a price of \$187/MWh with a 3.5% annual escalation. Because the \$2.6 billion total cost figure is sourced from the media and we were not able to confirm the dollar year of the reported number, we do not have strong confidence in the precise capital cost for this project in 2019\$. For purposes of including Cape Wind in our figures we have made the assumption that the \$2.6 billion cost was in 2016\$ given that the project cleared in Forward Capacity Auction 7. Though there is uncertainty around this number we believe it nevertheless does give insight into the general range of cost expectations for projects that were planned to be built approximately 10 years ago. We believe that costs have come down over the past decade, and yet ISO's current assumption is not far from the Cape Wind cost.

Response to CEA's Comments

Neither CEA nor the ISO have provided feedback on this data source.

Comparison to Reference Technology					
Suitability of Benchmark	Potential Reasons for Discrepancy				
Poor	Technology improvements (L), economies of scale (L), and installed cost (L)				

T 1 1 · DC

If one wanted to adjust the Cape Wind value to compare it on a completely level playing field with the ISO's reference technology, one would have to adjust the value to account for technology improvements over the past decade, economies of scale, and installed costs. The Cape Wind project was planned to use roughly twice as many (130) smaller turbines (3.6 MW) to achieve a smaller overall nameplate (468 MW). The reported value for the Cape Wind project is a total installed cost while ISO is reporting an overnight cost. Adjusting these to be consistent with the ISO's reference unit would likely result in a significantly lower value than the one reported. Therefore, we believe the value, as is, is a poor benchmark for the reference unit.

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		Shaded bands indicate the year of expected/actual commercial operation date 2016 2017 2018 2019 2020 2022 2023 2024 2025 2026
Specifications		
Title of Report	ORTP Calculation for FCA 8	
Publishing Year	2012	
Value (2019\$/kW)	\$5,747	
Range (2019\$/kW)	N/A	Ê 1,000
Size (MW)		
Location	New England	She to to the the she she she to the she she she she she she she she she s
COD	2017	A BACK AND A DAY
Installed/Overnight	Overnight	and a state of the
		 Publicly Available Data (Error Bars show cited ranges) ISO's Proposal
Source	Link	Outdated Data NEPOOL Alternative Other ISOs Cost Trendline
		*Installed Capital Costs †Overnight Capital Costs (excludes cost of interest during construction)

ISO-NE 2012

Publicly Available Offshore Wind Capital Cost Estimates

Description

In 2012 as part of the first ORTP calculation for FCA 8, the ISO's consultant Shaw Consultants International estimated the capital cost for a New England offshore wind project to reach COD before the start of the FCA 8 commitment period. Using publicly available sources, Shaw determined that \$4,905/kW (2011\$), equivalent to \$5,747/kW (2019\$), was an appropriate assumption. Most of the sources were not technical in nature but publicly available newspaper and magazine articles which cited capital costs. While this is not a bottom-up estimate and not the highest quality data, we believe (as ISO did in 2012) that this figure represents a reasonable representation of the expected prevailing market conditions at the time for projects expected to reach COD by 2017. In 2020, the ISO is claiming that prevailing cost expectations have decreased by less than seven percent to \$5,358/kW (2019\$) from where they were almost a decade earlier.

Response to CEA's Comments

Neither CEA nor the ISO have provided feedback on this data source.

Compo	rison to	Reference	Technology
compe	11001110	100,01000	100101089

Suitability of Benchmark	Potential Reasons for Discrepancy
Poor	Technology improvements (L) and economies of scale (L)

If one wanted to adjust the ISO-NE 2012 value to compare it on a completely level playing field with the ISO's reference unit, one would have to adjust the value to account for technology improvements and economies of scale. The ISO-NE 2012 project cost was developed 8 years ago when offshore wind technology was not as mature as it is today. In 2012 the average turbine size was approximately 3.6 MW and the average offshore wind project size was just under 250 MW. Adjusting these to be consistent with the ISO's reference technology would likely result in a significantly lower value than the one reported. Therefore, we believe the value, as is, is a poor benchmark for the reference unit.

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Publicly Available Offshore Wind Capital Cost Estimates

ifications		6,000	2016 2017	2018	2019	2020	2022	2023	2024	2025	
e of Report	ORTP Calculation for FCA 9	(MX)S6102) a		1	T	-	1	•	*	Ī	T
ishing Year	2013	3,000			11		+	11			-
ue (2019\$/kW)	\$5,700	2.000			- 1	1	1		÷		1
ge (2019\$/kW)	N/A	Capital									
(MW)	400	1,000									
tion	New England	0	52 150	15 12	12. 14	6 1	Day Any	Sy 12 02	Day Day Or	\$3, 40, 40, 10, 12,	10 1
)	2018		4 mg	St TOL	7 3018	12019*	Of Balt O	A	But And Rec On	018 020 018 019 ATB	100 AS
lled/Overnight	Overnight			~				San D.	San Dull	n p. Tonone	
		-	Publicly	Available	Data (Err	or Bars s	how cited ra	nges)IS	O's Proposal		
ce	Link	4	Outdated Other ISC	Data Os				N	EPOOL Alterna ost Trendline	tive	

ISO-NE 2013

Description

In 2013, the ISO performed a full recalculation of the ORTPs for use in FCA 9 using a bottom up approach much like what is being done currently for FCA 16. They determined that \$5,588/kW (2018\$) was an appropriate estimation of offshore wind overnight capital cost. This value is only 6% higher than the ISO's currently proposed value for the capital cost of a project that is double in size and will have a COD 7 years later.

Response to CEA's Comments

Neither CEA nor the ISO have provided feedback on this data source.

|--|

1 5	02
Suitability of Benchmark	Potential Reasons for Discrepancy
Poor	Technology improvements (L) and economies of scale (L)

If one wanted to adjust the ISO-NE 2013 value to compare it on a completely level playing field with the ISO's reference unit, one would have to adjust the value to account for technology improvements and economies of scale. The ISO-NE 2013 project cost was developed 7 years ago when offshore wind technology was not as mature as it is today. Adjusting these to be consistent with the ISO's reference technology would likely result in a significantly lower value than the one reported in 2013. Therefore, we believe the value, as is, is a poor benchmark for the reference unit.

Publicky Available Offebore Wind Canital Cost Estimator

Specifications	
	Renewable Power
Title of Demont	Comparation Costs in
The of Report	Generation Costs in
	2018
Publishing Year	2019
Value (2019\$/kW)	\$4,896
Range (2019\$/kW)	\$4,386-5,814
Size (MW)	400-550 MW
Location	European
COD	2018
Installed/Overnight	Installed
Course	T to b
Source	<u>L1nk</u>

IRENA 2018

Description

The International Renewable Energy Agency (IRENA) publishes an annual report with cost information for each offshore wind project around the globe that was commissioned in the prior year. In an attempt to utilize the most comparable data available with respect to the reference technology, rather than reporting the global average cost from IRENA, we report in our figure the installed costs for only European projects greater than 400 MW with a COD in 2018. These values were taken from Figure 3.3 of the IRENA report. The value that we reported is the simple average of all of the projects that met these criteria. The largest of these projects was approximately 550 MW and turbine sizes ranged from about 3 to 8 MW, substantially smaller than the reference technology.

Response to CEA's Comments

We met with the ISO and its consultants in June 2020 to provide feedback on their initial capital cost assumptions for offshore wind. MM's offshore wind expert pointed us to this specific report, the 2018 IRENA report, as a good benchmark for their capital cost assumption. They noted that Chinese data should be filtered out and that a cost premium should be assumed between the developed European market and the nascent American market. The reported range of \$4,300–\$5,700/kW (2018\$) that we cited from this report reflects the full range of costs reported for European projects over 400 MW with a 2018 commercial operation date. This range encompasses a variety of European countries, project sites, and project designs. As had been suggested by MM, we excluded Asian project costs from our numbers. There are no offshore wind projects over 400 MW operating on any continent other than Europe and Asia, so by default all of the data included in our reported numbers came from Europe.

While the single most expensive European project over 400 MW in size that was commissioned in 2018 cost slightly more (\$5,814/kW) than the ISO's proposed cost assumption (\$5,358/kW), the 2019 IRENA report shows that just one year later the single most expensive European project over 400 MW cost one third less than this, just \$3,900/kW. The average cost of European offshore wind projects over 400 MW dropped from \$4,896/kW in 2018 to \$3,500/kW in 2019. If the ISO is using IRENA data to benchmark their capital cost assumptions, then they

should at the very least be utilizing the most recently available data from 2019 rather than the older 2018 data.

If they are using the most recent data from 2019 then they must be applying a significant premium for building a comparable size and scope project in the United States. Using the 2019 IRENA report, the ISO would need to be assuming a premium of roughly \$1,500/kW or \$1.2 billion for building in the United States in 2025 as compared with the most expensive project over 400 MW built in Europe in 2019.

CEA claimed in its October 2020 presentation to the NEPOOL Markets Committee that RENEW's quoted values of \$4,300–\$5,700/kW (2018\$) from the IRENA 2018 report were derived from European projects, some of which would be "better categorized as demonstration projects", citing IRENA at 24. This quote appears to have been pulled out of context and is not applicable to the numbers that we reported. The full quote from IRENA at 24 that CEA was referring to is: "The LCOE in Japan is high in comparison to China, at an estimated USD 0.20/ kWh given that projects to date are small in scale and are perhaps better categorized as demonstration projects." As the full quote makes clear, the demonstration projects were Japanese projects. Boreas did not include any Asian projects in its analysis and therefore this quote does not apply to the numbers we reported.

Comparison to Reference Technology

1 3	
Suitability of Benchmark	Potential Reasons for Discrepancy
Poor	Technology improvements (L), location (R), installed cost (L), and economies of scale (L)

IRENA published a newer report, the 2019 report discussed next, that provides more recent data than this one. For that reason we have marked this one as outdated in our figure. If one wanted to adjust the IRENA 2018 value to compare it on a completely level playing field with the ISO's reference unit, one would have to adjust the value to account for technology improvements, location, and economies of scale. The values in the IRENA report are for projects that are smaller and have older technology. Newer larger projects would have lower costs. There may need to be some upward adjustments to account for differences between European and United States costs. Because this data is out of date, we believe the value, as is, is a poor benchmark for the reference unit.

Publicly Available Offshore Wind Capital Cost Estimates

Specifications			Shaded bar 2016 2017	2018	the year of 2019	expected 2020	2022	nercial operation 2023	n date 2024	2025	
Title of Report	Renewable Power Generation Costs in 2019	6,000 (M3 5,000 ate 4,000	1	-			1	•	÷		T
Publishing Year	2020				Y.	+		I I	I		-
Value (2019\$/kW)	\$3,500	00 2,000			1	-	1		T	1.	1
Range (2019\$/kW)	\$2,800-3,900	Capit 1,000									
Size (MW)	400 - 600 MW	0									
Location	European		San iso	150,12	ARD LAD	Labara	Day PIN	ELA, MR. Day	Desing the	SA DOR DOR MR. MAS	NERO S
COD	2019		- Ino	1. 2013 A	2018.	2019*	So. "+	(Inc. CP.	* Wine Revo	015, 20, 015, 010, AB	10, 02
Installed/Overnight	Installed							and D.	Sand ID.	an D. D.	
		-	Publicly	Available	e Data (Err	or Bars s	how cited n	anges) IS	O's Proposal		
Source	Link	4	Outdated Other IS	d Data Os				N	EPOOL Alterna ost Trendline	tive	

IRENA 2019

Description

The numbers reported in our figure are the installed costs for European projects greater than 400 MW with a COD in 2019. These values were taken from Table 4-4 of the report. The value that we reported is the simple average of all of the projects that met these criteria.

Response to CEA's Comments

CEA has claimed that it is inappropriate to compare European capital cost numbers to United States capital cost numbers because the scope of work is different for developers in these countries. While the scope of work may not be the same between all European projects and projects in the United States, there are countries in Europe (Germany and UK) where the developers are responsible for the cost of export cables and interconnection just like in the United States.

IRENA reports that the weighted average cost of all German projects with a 2019 COD (including projects under 400 MW in size which were excluded from the Boreas numbers) was \$4,077/kW. This is actually lower than the weighted average cost of all European projects with a 2019 COD, \$4,094/kW. IRENA notes that the UK projects had the highest average distance to shore, 70 miles (ten miles further than the reference project being used in the ORTP analysis), which they noted could account for their higher weighted average cost of \$4,580/kW. It appears from the data that the bulk of the European projects built in 2019 were located in one of these two countries and that the total European numbers cited by Boreas are more heavily representative of the costs of projects built in countries where the project is responsible for transmission and interconnection costs just like in New England.

Even if looking at only the country with the highest costs, the UK, where distance to shore and export cabling costs are known to be higher than for the ORTP reference project, for projects of all sizes not just large projects, the ISO's proposed cost assumption for a much larger project to be built in 2025 represents a \$778/kW or \$0.62 billion premium over the average cost of all projects built in the UK in 2019.

Comparison to Reference Technology

Suitability of BenchmarkPotential Reasons for DiscrepancyFairCOD (L), location (R), installed cost (L), and economies of scale (L)

If one wanted to adjust the IRENA 2019 value to compare it on a completely level playing field with the ISO's reference project, one would have to adjust the value to account for technology improvements and economies of scale. The values in the IRENA 2019 report are for projects that are smaller and have older technology. Newer larger projects would have lower costs. There may need to be some upward adjustments to account for differences between European and United States costs. Because this data is for CODs six years earlier than the reference project but is the most recent data available for actual installed project costs, we believe the value, as is, is a fair benchmark for the reference unit.

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Publicly Available Offshore Wind Capital Cost Estimates

		6 000	Shaded bands in 2016 2017 20	18 2019	of expecte 2020	d/actual conn 2022	nercial operatio 2023	n date 2024	2025	2
Specifications		5	1 .	Ţ						
Title of Report	2019 Levelized Cost of Energy Report v.13.0	(N/S6102) ate 4,000		-	-	1	•	*	I.	T
Publishing Year	2019	3,000		10)	-	1 1	T		
Value (2019\$/kW)	\$2,925	2,000 E			1	1		•	11.	1
Range (2019\$/kW)	\$2,330-3,530	Capit								
Size (MW)	210–385	0			_					
Location	Global		St. 50, 50	10, 10,	Antana A	ALS BASIN	A. 180 3	Des Des tor t	A 40, 40, 18, 13,	NED SQ
COD	2019		"Inda	C 2013 1918	2010,010,	0.0* "#	AP.	t * Wine Revolution	18. 020. 018. 019. ATB	By or.
Installed/Overnight	Installed						and De	Sand ID.	D.	
		-	Publicly Ava	ilable Data (I	Fror Bars	show cited r	anges) 19	SO's Proposal		
Source	Link	-	Outdated Da Other ISOs	ta			N	EPOOL Alternativ ost Trendline	ve	
·		*Installed Ca	pital Costs	wahadar aart	afintarat	during associate	tenation)			

Lazard 2019

Description

The Lazard value we cite comes from the Lazard Levelized Cost of Energy (LCOE) Report. The capital cost assumption in this report is derived from surveys and press releases from actual projects around the world. Lazard specifically tries to find the extremes within these results to create a range of reasonableness (both the high and low ends globally). This data represents current costs and is not a projection of future costs.

Response to CEA's Comments

As CEA noted, this data does not include network upgrades, transmission, congestion, permitting, and environmental costs. As seen in the figure this is one of the lowest data points on the chart, including being lower than the NEPOOL Alternative capital cost value despite representing a COD six years earlier than the reference project. If costs continue to decline between 2019 and 2025, as is the commercial expectation, then this point would be expected to fall even further. Adding back in the excluded cost, we believe you would end up in a range consistent with NEPOOL's value and not the ISO's for a project with a COD in 2025.

Comparison to Reference Technology

Suitability of Benchmark	Potential Reasons for Discrepancy
Fair	COD (L), location (?), scope (R), and installed cost (L)

Lazard published a newer report, the 2020 report discussed next, that provides more recent data than this one. For that reason we have marked this one as outdated in our figure. If one wanted to adjust the Lazard value to compare it on a completely level playing field with ISO's reference unit, one would have to adjust the value to account for technology improvements and location, and to convert installed costs to overnight costs. As noted earlier, the scope would need to be expanded to cover the excluded cost components which would raise the estimate. If one felt a regional adjustment needed to be made (either up or down) one would need further insight into the data. However, given that this is current data, representative of global capital costs, we believe that it is a fair benchmark for the reference unit with the above caveats kept in mind.

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Publicly Available Offshore Wind Capital Cost Estimates

		Sha	ded bands indic	ate the year o	of expected	actual comm	tercial operatio	n date	2025	
pecifications		6,000	A A	2019	2020	2022	2023	2024	2025	
Title of Report	2020 Levelized Cost of Energy Report v.14.0	N3 5,000 35,000 4,000 at		-		1	•	*	I	T
Publishing Year	2020	- 3,000 Egi		1	()	T	11	T		
Value (2019\$/kW)	\$3,076	2,000		1	I	1		÷		1
Range (2019\$/kW)	\$2,549-3,603	Capita								
Size (MW)	210-385									
Location	Global		1 50 SQ.	20, 10, 4	13 M	Day Pit	04, 12, 03	Day Day CAY	50 400 100 100 1V2	NED S
COD	2020		Winds 2013	2013, 2018.	2010	Or text	in the	ANTA CANA CANA CANA	015. 020. 015. 019. AB	83,01
Installed/Overnight	Installed						Sand D.	Sand ID.	Tower.	
		A P	ublicly Availal	ole Data (Er	ror Bars s	how cited ra	nges) 19	O's Proposal		
Source	Link		utdated Data ther ISOs				N	EPOOL Alterna ost Trendline	tive	

Lazard 2020

Description

The Lazard value we cite comes from the Lazard Levelized Cost of Energy (LCOE) Report. The capital cost assumption in this report is derived from surveys and press releases from actual projects around the world. They specifically try to find the extremes within these results to create a range of reasonableness (both the high and low ends globally). This data represents current costs for 2020 and is not a projection of future costs. The capital cost estimate in Lazard 2020 increased slightly (5%) from the Lazard 2019 report but still remains well below ISO's proposal.

Response to CEA's Comments

Neither CEA nor the ISO have provided feedback on this data source.

Comparison to Reference Technology						
Suitability of Benchmark	Potential Reasons for Discrepancy					
Good	COD (L), location (?), scope (R), and installed cost (L)					

If one wanted to adjust the Lazard value to compare it on a completely level playing field with the ISO's reference unit, one would have to adjust the value to account for technology improvements and location, and to convert installed costs to overnight costs. As noted in the Lazard 2019 description, the scope would need to be expanded to cover the excluded cost components which would raise the estimate. The Lazard value is representative of current projects, so an adjustment would need to be made to capture technology changes between 2020 and 2025. If one felt a regional adjustment needed to be made (either up or down) one would need further insight into the data. However, given that this is current data, representative of global capital costs, we believe that it is reasonable to benchmark the reference unit against this value as it is.



<u>NYISO</u>

Description

In December 2020, NYISO presented results of their Buyer Side Mitigation ("BSM") Renewable Exemption Study to their stakeholder group based on a report compiled for the NYISO by Sargent & Lundy on the capital costs of renewable technologies.⁷⁹ Sargent and Lundy estimated the capital costs for a variety of renewable technologies expected to reach commercial operation in 2020, including a capital cost estimate for an 800 MW offshore wind project utilizing turbines rated between 6 and 12.5 MW each. The conceptual project was located in the New York Bight 30 miles offshore. Sargent and Lundy provided a capital cost breakdown of each of the elements in their estimate, summing to a total capital cost of \$4,277/kW (2020\$).

Response to CEA's Comments

Neither CEA nor the ISO have provided feedback on this data source.

Comparison to Reference Technology

Suitability of Benchmark	Potential Reasons for Discrepancy
Good	COD (L), scope (?), and location (L)

If one wanted to adjust the NYISO value to compare it on a completely level playing field with ISO's reference unit, one would have to adjust the value to account for technology improvements, project scope, and location. As noted in the Sargent and Lundy description, the scope would likely need to be expanded to cover the cost of additional offshore export cabling to

⁷⁹ New York ISO. BSM 7. Renewable Exemption Study, at 9 (Dec. 2020), https://www.nyiso.com/documents/20142/17450815/December_7_2020_BSM_Renewable_Study_ICAP WG FINAL%20(002).pdf/5c9d4577-9133-0a36-1f57-0d5b1a57bac0 (noting that a Sargent & Lundy report, which was posted with the meeting materials, provided the "Total Estimated Capital Expenditure (CAPEX) and Operations & Maintenance (O&M) Cost"); see also Sargent & Lundy, Renewable Technology Costs; Prepared for New York ISO, Final, Project A14045.022 (Jun. 25, 2020), https://www.nyiso.com/documents/20142/17450815/NYISO_Renewable%20Technology%20Costs_26Ju ne2020public.pdf/25661725-15bd-33e2-1fdb-d883f9f82963.

match the ISO's assumption of 60 miles. The NYISO value is representative of a hypothetical project reaching COD in 2020, so an adjustment would need to be made to capture technology changes between 2020 and 2025. One would also need to adjust to account for regional differences between NY and New England. By EIA regional adjustment factors, this would likely decrease the total capital costs slightly.
Specifications					Publich	y Availa	ble Offst	ore Wind (Capital Cos	st Estimates		
	Preliminary Default	Ē	Shaded band	s indicate	the year of	f expected	Vactual com	nercial operatio	n date 2024		2025	2025
	MOPR Floor Offer	6,000	1.	A [
Title of Report	Prices for New	NX 5,000	-	1			0			I		
L	Generation Capacity	102 4,000		1	T	-	Ų	a T	1	T	T	T
	Resources	15 3,000			1-1-	1	+	1.			×	-
Publishing Year	2020	000 C OST			•	1	1		Ŧ		1	1
Value (2019\$/kW)	\$4,375	Capital										
Range (2019\$/kW)	\$2,350-4,529	- 1,000										
Size (MW)	400	0 1	S. 10.	50.12	120.60	41	Day Pin	SI 12 03	00 00 0	2 62 00,00	4	NR 1
Location	PJM		4 Inde	E TOIN	7 3018	1010 × 010	SO, Bark	A	Start Cart Re.	1018 020 018 .	201	019, A.
COD	2023				-			Stand De	Stard II)	Hation D.		
Installed/Overnight	Installed	-	Publicly A	vailable	Data (En	or Bars	how cited n	anges) 15	SO's Proposal			
			Outdated I	Data				N	EPOOL Alter	mative		
Source	Link	*Installed Ca	apital Costs	s					ost Trendline		_	

<u>PJM</u>

Description

PJM made a presentation to the Market Implementation Committee on February 28, 2020 titled "Preliminary Default MOPR Floor Offer Prices for New Generation Capacity Resources." Slide 4 gives an assumed capital cost of \$4,375/kW for a 400 MW project, taken from EIA's AEO2019. Slide 14 lists the capital costs in each of the sources reviewed by PJM in their literature review, ranging from \$2,350–\$6,323/kW. PJM selected the second highest cost among the sources reviewed that represented a fixed-bottom turbine rather than a floating turbine (of the values reviewed by PJM, those above \$4,529/kW were for turbines on floating platforms and we have therefor excluded them from our reported values).

Response to CEA's Comments

As CEA noted, PJM relied on many of the same sources to develop their capital cost estimate for offshore wind as Boreas has cited in its literature review. As Boreas has also been highlighting, PJM felt that these sources were appropriate benchmarks.

CEA notes that the PJM cost we cited did not account for regional adjustments for the New England location. According to the EIA Annual Energy Outlook (AEO), offshore wind costs in PJM are higher than those in New England. So, if this were true, we would expect New England costs to be lower than PJM's assumption. However, ISO's current assumption is that costs in New England would be 22% higher than what PJM assumes, and FERC has accepted, as a reasonable cost for the mid-Atlantic.

Comparison to Reference Technology

Suitability of Benchmark	Potential Reasons for Discrepancy
Good	COD (L), location (L), installed cost (L), and economies of scale (L)

If one wanted to adjust PJM's value to compare it on a completely level playing field with the ISO's reference unit, one would have to adjust the value to account for technology improvements, location, and economies of scale, as well as convert it to an overnight cost. All these adjustments would lower the value reported on the figure. However, we still believe that the value PJM decided to use is a reasonable benchmark for the reference unit.

ER21- -000 Attachment N-1b – Testimony of Abigail Krich

Publicly Available Offshore Wind Capital Cost Estimates

			Shaded band	s indicate the ye	ar of expects	d/actual con	imercial operatio	on date	2016	
Specifications		6,000	-	2018 2019 A	2020	2022	2023	2024	2023	
Title of Report	Annual Energy Outlook	W3/560		-		T	0		I	
Publishing Year	2020	80 4,000 #		I	T	+		Ŧ	I	
Value (2019\$/kW)	\$4,356	-Ester 3,000		Ī	1		I I	Ŧ	. 1	•
Range (2019\$/kW)	N/A	⁸ 2,000							1	
Size (MW)	400	5 1,000								
Location	United States	0	G 40	10 40 40	6.67	has	6 16 4	000		45
COD	2023		the Winds	10, 10, 10, 10, 10, 10, 10, 10, 10, 10,	Sand Solo	ALSO STRAT	To My MEL	That C. O	A 10 00 00 00 00 00 00 00 00 00 00 00 00	AL ALS
Installed/Overnight	Overnight			3× 3× 0			In Dand In	Incy and I	Control Control	
			Publicly A	vailable Data	Error Bars	show cited	ranges) 1	SO's Proposal	. 9	
Source	Link	:	Outdated Other ISC	Data			N	EPOOL Alter	mative	

Description

Table 1 of the Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2020 report published by the U.S. Energy information Administration shows the base cost for a 400 MW offshore wind project to be commercial in 2023 is \$4,356/kW. On that same line in the table it also provides an adjusted cost of \$5,446/kW, which it notes is applicable for only the first four units installed. At least seven contracted US offshore wind projects have planned CODs prior to 2025. As noted in our Markets Committee presentations, we did not assume that the ORTP reference project with a 2025 COD is among the first four offshore wind projects built in the US, which is why we did not include this adjustment. Table 2 uses the cost for the first four offshore wind units and shows the regional adjustments that should be applied. This table shows that there is no regional adjustment from the base overnight capital cost for the ISO-NE region.

Response to CEA's Comments

CEA claimed that we under-represented the EIA cost estimate by neglecting to include a \$1,090/kW "locational adder." CEA appears to have misread the EIA's report, as EIA's report shows clearly that there is no locational adder for New England as compared with their base cost. The \$1,090/kW adder CEA referenced is actually a "technological optimism" factor that EIA notes is only to be applied to the first four offshore wind projects. Because the reference project has a 2025 COD, it is not among the first four offshore wind projects planned for completion in the United States and this technological optimism factor would therefore not be applicable. The EIA's base cost of \$4,356 is therefore an appropriate value to use to compare to ISO's assumption. We believe it is also noteworthy that PJM, in adopting the EIA AEO2019 projection of offshore wind cost for use in setting their Floor Offer Price, which was approved by the Commission, similarly did not include the EIA's "technological optimism" factor in their offshore wind cost assumption.

Comparison to Reference Technology

Suitability of Benchmark	Potential Reasons for Discrepancy
Good	COD (L) and economies of scale (L)

If one wanted to adjust PJM's value to compare it on a completely level playing field with the ISO's reference unit, one would have to adjust the value to account for technology improvements and economies of scale. Because the reference unit has a later COD and is a larger project, all these adjustments would lower the value reported on the figure. However, we still believe that the value EIA reported is a reasonable benchmark for the reference unit.

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<u>NREL PPA</u>				Public	ly Avail:	ble Offsl	ore Wind C	apital Cost Est	timates	
		Shi	aded bands ind	icate the year	of expecte	Vactual com	nercial operation	date	2026	2026
Specifications		6,000	A A	2019	2020	2022	2023	2024	2025	2026
Title of Report	Vineyard Wind PPA Analysis	M3(\$6102) av	/	T		1	•	A.		T
Publishing Year	2018	etti 3,000		-		*	Q.			
Value (2019\$/kW)	\$3,500	D 2,000		1	1	1		÷		1
Range (2019\$/kW)	\$3,000-4,000	Capita								
Size (MW)	800	1,000								
Location	New England	0 1 0	00.00	10, 10,	a 12 1	Day Pin	DIA VRD Day	Day Day Con Co	- 40, 40, 18, 12,	10, 50, 00
COD	2023		Winds 201	K 1013	2010-010-	SOF Start	APA	ant Cin Re. Osp	\$020 \$018 \$019 \$1B	NO OL NE
Installed/Overnight	Installed						Dard D.	San Didion	OH GY	
		A P	ublicly Avail	able Data (E	error Bars	show cited r	anges) IS	O's Proposal		
Source	<u>Link</u>	▲ C ▲ C	Outdated Data Other ISOs				NI	EPOOL Alternative st Trendline	e	
		*Installed Capit †Overnight Cap	tal Costs oital Costs (ex	cludes cost	of interest	during cons	truction)			

NREL PPA

Description

In 2018, the National Renewable Energy Laboratory (NREL) looked at the Vineyard Wind PPA to attempt to calculate an implied levelized cost of energy (LCOE). As part of that analysis, they had to assume a capital cost. Using European data from Bloomberg New Energy Finance, they determined that \$3,500/kW was an appropriate baseline value for capital cost in their model. Recognizing the uncertainty in the value, they also studied capital costs \$500/kW greater and less than \$3,500/kW. Based on this analysis, \$3,000-4,000/kW was the range NREL believed was appropriated for the Vineyard Wind project, which has very similar specifications to the reference project in the ISO's calculations.

Response to CEA's Comments

CEA concluded its October 2020 Markets Committee presentation by saying that the NREL analysis that "uses a PPA rate to solve for capex freely acknowledges that PPA rates may not fully cover the cost to build and operate a given project."⁸⁰ This appears to be referring to the NREL PPA analysis in our literature review, but mischaracterizes the NREL analysis as one which solved for the capex based on the PPA rate. Rather, as we have described above, the NREL analysis selected an assumed capital cost from the literature and was not attempting to solve for the capital cost. As far as we can tell, this paper also made no acknowledgement that PPA rates may not cover a developer's cost to build and operate a project.

As CEA highlighted in their presentation there is a significant amount of uncertainty regarding many of the parameters considered by NREL in their Levelized Revenue of Energy (LROE) analysis and that the analysis represents a first order estimation. However, in the same paragraph on page 11 that CEA cites, NREL also notes that "this LROE can serve as an initial reference for bottom-up cost modeling but should be validated further as more information from the Vineyard Wind LLC/EDC PPA and broader industry and supply chain development in the United States become available."

⁸⁰ CEA Oct. 2020 PPT at 4.

ER21-___-000 Attachment N-1b – Testimony of Abigail Krich

At the time this report was published the Vineyard Wind PPA was the only recent, large US offshore wind contract with public pricing terms, so hypotheses regarding strategic bidding behavior were reasonable and fairly widespread. Now, there are numerous executed offshore wind contract prices publicly available that show that Vineyard Wind's contract price is not out of line with other PPA rates. In our opinion, there is no strategic advantage to be economically unprofitable when your project is not even going to be one of the first facilities constructed.

Comparison to Reference Technology

1	•		
Suitability of Ben	chmark	Potential Reasons for Discrepancy	
Good		Installed Costs (L) and COD (L)	

If one wanted to adjust NREL's value to compare it on a completely level playing field with the ISO's reference unit, one would have to adjust the value to account for technology improvements and convert the value to an overnight capital cost. Because the reference unit has a later COD, this adjustment would slightly lower the value reported in our figure. However, we still believe that the value NREL reported is a reasonable benchmark for the reference unit.



<u>EPA 2018</u>

Description

In the EPA's Power Sector Modeling Platform v6 November 2018 Reference Case, the base case capital cost assumption for a 600 MW offshore wind project with a vintage of 2025 was \$4,122/kW (2016\$) as seen in Table 4-16. To tailor this base case scenario for the MA offshore lease area, one must include a 6.8% locational adder (Table 4-15), resulting in a value of \$4,402/kW (2016\$), which after an adjustment to 2019\$ is the value included in our figure.

Response to CEA's Comments

CEA suggested that we should have included a short-term capital cost adder of \$1,893/kW (Table 4-14). The short-term capital cost adders are dependent on assumptions about how much capacity is added each year. CEA did not discuss with the Markets Committee that they had made any such assumption that over 1,150 MW of offshore wind would be built in 2025, the same year as the reference unit, triggering the adder. Our figure does not reflect the short-term capital cost adder for this reason. Further, in the EPA's Jan 2020 update, discussed next, they eliminated the short-term capital cost adder for offshore wind.

Comparison to Reference Technology

Suitability of Benchmark	Potential Reasons for Discrepancy
Poor	Installed Costs (L), Size (L)

An updated version of this report was published by EPA in January 2020 that includes an updated value of the EPA's capital cost estimate for offshore wind. We have therefor marked this version "outdated" in our figure. However, if one wanted to adjust EPA's Nov 2018 value to compare it on a completely level playing field with the ISO's reference unit, one would have to adjust for project size and convert the value to an overnight capital cost.



<u>EPA 2020</u>

Description

In January 2020, the EPA updated the reference case for their Power Sector Modeling Platform. As part of these changes, the EPA updated their capital cost estimate for offshore wind technologies in Table 4-16, such that:

The offshore wind technology cost assumptions from NREL ATB 2019 mid case are approximately modeled by scaling the capital costs and FOM in EPA's November 2018 Reference Case.⁸¹

This update decreased the EPA's estimated base case capital cost for a 2025 offshore wind facility from \$4,122/kW for a 600 MW project in the Nov 2018 reference case to \$2,686/kW for a 400 MW project in the Jan 2020 reference case (both 2016\$). With the regional adjustment from the Nov 2018 case, which was not updated, a capital cost for a MA offshore wind project could be calculated to be \$2,869/kW (2016\$), which after adjustment to 2019\$ was included in our figure.

This significant cost decline between 2018 and 2020 in the EPA's capital cost estimate is indicative of the cost savings developers have been able to realize in just the last two years. Estimates that are even only two years old no longer reflect commercial expectations for new projects, especially those to be built 5 years in the future.

Response to CEA's Comments

Neither CEA nor ISO have provided feedback on this data source.

Comparison to Reference	Technology
Suitability of Benchmark	Potential Reasons for Discrepancy
Good	Installed Costs (L), Size (L)

⁸¹ EPA Jan. 2020 Reference Case at 20.

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If one wanted to adjust EPA's value to compare it on a completely level playing field with the ISO's reference unit, one would have to adjust for project size and convert the value to an overnight capital cost. However, because the difference between overnight and installed costs on a per kW basis is relatively small, we still believe that the value EPA reported is a reasonable benchmark for the reference unit.



DOE 2018

Description

The range we cite here, \$2,500–\$4,000/kW, is the Department of Energy's (DOE) projection for the range of global offshore wind capital costs between 2020 and 2030, which can be found on page 59. While the DOE recognizes the uncertainty in what had been included in their survey results of individual project costs and the locational variations among projects, we believe this projected cost range to be encompassing of all scopes of work and all countries and therefore is applicable for a 2025 project in New England.

Response to CEA's Comments

CEA referenced a figure on page 59 of the DOE report that depicts cost data for two hundred twenty-eight individual offshore wind projects around the world. CEA pointed out that the data in this figure is not specific to projects in the United States but instead the lowest 2018 cost was from a project in China and the highest was from a project in the UK. We agree that this is a correct characterization of the figure on page 59 of the DOE report. However, this figure was not used in the Boreas literature review. Instead, the Boreas materials cite the DOE's projected range of global costs that are expected for projects with commercial operation dates between 2020 and 2030, which range from \$2,500 to \$4,000/kW.

CEA cited a disclaimer in the DOE report regarding the uncertainty of the individual project cost numbers in the figure on page 59: "These CapEx data have some uncertainty for various reasons: 1) the CapEx data are normally self-reported by developers and difficult to verify independently, 2) there is limited transparency into the financial impact of cost overruns, and 3) it is often unclear whether the reported CapEx fully captures the total cost of installing the project and connecting it to the grid' (DOE Report, at 60)" This quote from the DOE report is a bit misleading when taken out of context. The next sentence in the report reads, "When viewed together, though, these data can provide insight into the long-term cost trends. Generally, greater confidence can be placed in cost estimates that are in more mature stages of the project life cycle (i.e., costs for projects that have reached the financial investment decision are typically more accurate than for a project that has not yet received permits); however, preliminary estimates provide insight into developer expectations about cost trends."

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We acknowledge the disclaimers that the DOE added to their report, and that CEA cited. There is uncertainty in what is included in reported values that were collected for capital costs. We would not expect anyone to rely on this data alone for developing an estimate but do believe that it provides insight into the general range of reasonableness regarding developer expectations about cost trends for this type of project, particularly their projection for future costs.

Comparison to Reference Technology

	82
Suitability of Benchmark	Potential Reasons for Discrepancy
Poor	Installed Cost (L)

DOE published a newer report, the 2019 report discussed next, that provides more recent data than this one. For that reason we have marked this one as outdated in our figure. Because this estimate is broad, all-encompassing, and not specific to a particular location or project configuration, we believe that the ORTP reference unit should be expected to fall within it.

Publicly Available Offshore Wind Capital Cost Estimates

Specifications		6,000 2016 20	17 2018	2019	2020	2022	2023	2024	2025	-
Title of Report	2019 Offshore Wind Market Data	(M35,000	Í			Ŧ	•	*		
Publishing Year	2020	miliate		1.	I	ł		*		
Value (2019\$/kW)	\$3,050	150 to		1	Î			Ŧ	Ψ	1
Range (2019\$/kW)	\$2,200-4,900	0 2,000								
Size (MW)		Ö 1,000								
Location	Global	0			1 1	0.0	A 4 A	0000		_
COD	2025	St.	SO NE Y	CLAR STAN	and to the to	SO, Datt	AN RELAD	A A A A A A A A A A A A A A A A A A A	PA JOE JOE WELLY	SS.
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Source	<u>Link</u>	Publi Outd Othe	cly Available ated Data 1SOs	e Data (Erro	x Bars sl	iow cited ra	nges) I! N	SO's Proposal EPOOL Alternati ost Trendline	ve	

DOE 2019

Description

On October 8, 2020, DOE released their latest Offshore Wind Market Data report which includes reported capital costs for hundreds of individual offshore wind projects around the world, including those that were installed between 2010 and 2019 as well as those that are under construction, contracted, approved, or in permitting to be operational by 2030. We have reported from this data the range of costs for all projects around the world that are expected to reach COD in 2025 (\$2,200–\$4,900/kW) as well as the global 5-year rolling average capital cost from 2025 (\$3,050/kW). Considering that the numbers here represent global projects we expect that US numbers will fall within this range.

Response to CEA's Comments

Neither CEA nor the ISO have provided feedback on this data source.

Comparison to Reference	Technology
Suitability of Benchmark	Potential Reasons for Discrepancy
Good	Location (?), Installed (L)

The reported capital cost range of \$2,200–\$4,900/kW reflects the full known range of expectation for the cost of each offshore wind project around the world that is planned for 2025 COD. As US and New England projects are included in this data set, we would expect local project costs to fall within this range.

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Publicly Available Offshore Wind Capital Cost Estimates

		5	shaded band	ds indicate	the year of	expected	actual com	mercial operatio	n date		
		5 000	016 2017	2018	2019	2020	2022	2023	2024	2025	
ecifications		ŝ	1.								
tle of Report	Annual Technology Baseline	5,000 4,000 4,000		1		T	Ŧ	•	+		I
blishing Year	2020	·			1	1		Ŧ	I A	· •	-
alue (2019\$/kW)	\$3,213	0 2,000			1		1		-	1	-
ange (2019\$/kW)	\$2,541-3,900	S 1,000									
ze (MW)	600	0					, , ,				
ocation	United States		She to	50.12	THE LAS	Land N	Day P.M.	ALA, 18603	Dayman Dayman 20	A DOR DOR MARTINE	NIROS
)D	2025		Ind.	1012	3,018.	19. 019. V	30. Y	Amer .	A Chines Ches	f. to, "f. "o, "B;	04.2
talled/Overnight	Overnight							"dD.	and ID * High	1. C).	
		•	Publicly /	Available	Data (Err	or Bars s	how cited r	anges) 19	SO's Proposal		
urce	Link	1	Outdated Other ISC	Data Os				N	EPOOL Alternativ ost Trendline	e	

NREL ATB

Description

The National Renewable Energy Laboratory's Annual Technology Baseline report is a detailed cost and performance data set for all renewable and non-renewable power generation technologies that represents current and projected values for these technologies. For offshore wind, there are cost estimates for a variety of categories based on wind speed, water depth, and distance to shore. We chose the offshore wind reference category in the ATB report ("Techoresource group 6") that we believe aligns closest with the hypothetical ORTP project based on the project design characteristics. Because none of the ATB values perfectly match the ORTP project, where there was doubt between the appropriate ATB reference group we erred on the side of selecting the higher cost group to be conservative. Only one other techno-resource group for fixed bottom wind turbines had a higher cost (by \$2/kW) than the one we reported.

Response to CEA's Comments

CEA argued that the ATB numbers had insufficient detail to be used as a benchmark because "it's not clear what region of the US these cost estimates relate to." The value reported for NREL's Annual Technology Baseline is a projection specific to a 600 MW project with a 2025 COD. Costs for an 800 MW project should be somewhat lower than this. The blue triangle shown in the figure above is for the project characteristics that most closely match the ORTP project in terms of distance to shore, water depth, and wind speed, using their mid-range expectations for technology maturation. The range shown is the full range of projected costs for all of the fixed bottom project characteristics and assumptions that NREL evaluated including their most optimistic and most conservative assumptions about technology maturation over the coming years. The ATB numbers do not have regional adjustments, but the bulk of the offshore wind development in the US is happening in the northeast and mid-Atlantic currently so the costs for the offshore wind reported in ATB can be assumed to apply to this region. As noted earlier for the EIA report, there is no upward regional adjustment for New England from the baseline overall US offshore wind costs, so even if the ATB were focused on a different region of the country it would then follow that the New England costs should be equal to or lower than those reported in the ATB.

Comparison to Reference Technology

Suitability of BenchmarkPotential Reasons for DiscrepancyExcellentLocation (?)

NREL's ATB report provides a cost estimation based on NREL's own cost estimation tool developed specifically for offshore wind. The parameters of the techno-resource group align closely with the reference unit. The only potential difference would be a regional adjustment downward for New England, which would likely be insignificant compared to average US baseline costs, as seen in the EIA AEO report.

Publicly Available Offshore Wind Capital Cost Estimates

Specifications		6,000	Shaded bar 2016 2017	2018	e the year o 2019	2020	2022	2023	2024	2025
Title of Report	White Paper on Clean Energy Standard Procurements	nate (2019S/KW) 4'000	1	-		T	Ŧ	•	1	
Publishing Year	2020	000,E Esti-			1 .	t		ĮĮ	Ŧ	
Value (2019\$/kW)	\$3,155	⁰ 2,000			-		-			1
Range (2019\$/kW)	N/A	e 1,000								
Size (MW)	800	0								
Location	New York		Cane 450	150 18	ALA LA	Land A	Dayman Pix	CIA, NREI A	Dayman CPA	10, 00, 00, 18, 11 10, 10, 10, 10, 10, 10, 10, 10, 10, 10,
COD	2025		-26	10 TO 13	013,018.	19, 19,	30. 1	Lines.	A. W. Revolu	19° . 0° . 9° . 0° .
Installed/Overnight	Installed							""D.	"d ID "O	D***
		1	Publicly	Available	e Data (En	for Bars	how cited r	anges) 1	SO's Proposal	
Source	Link	1	Other IS	Os					Cost Trendline	ve

NYSERDA

Description

Renewables Consulting Group conducted a detailed capital cost estimation for the New York Department of Public Service (NY DPS) and the New York State Energy Research and Development Authority (NYSERDA) of an 800 MW project located in the New York Bight with an AC interconnection and 2025 COD (identical to the ORTP reference project except in location). The NY DPS/NYSERDA report provides the line-item cost breakdown shown in the table below. The total capital cost figure of \$3,155/kW is consistent with that of the other literature for comparable projects. In addition, the whitepaper noted that the cost was benchmarked against actual bids received by NYSERDA in its 2018 offshore wind solicitation (whose winners had similar PPA prices to those awarded in New England) and found to "fall within a similar range, providing confidence in the model's underlying technology cost and financing cost assumptions."

NYSERDA/NY DPS Base Case Estimate	(2019\$kW)
Project Development	264
Turbine Supply	1,174
Foundation Supply	415
Installation of Turbines and Foundations	256
Supply and Installation of Array Cables	106
Supply and Installation of Substations	301
Supply and Installation of Export Cables	280
Other	361
Total	3,155

The figure below compares this cost breakdown to the ISO and NEPOOL proposals. It can be seen clearly in this figure that the NEPOOL and NYSERDA/NY DPS costs align closely.



Substations Export Cables Interarray cables Major Equipment Project Development Other

It is worth noting that the NYSERDA base case cost estimate excludes three smaller line items that are included in the ISO and NEPOOL Alternative cost estimates. The ISO and NEPOOL Alternatives include a small cost (up to tens of millions of dollars) for network upgrades, while the NYSERDA estimate excludes network upgrade costs. The ISO and NEPOOL Alternative costs include financing fees equal to 4% of costs financed through debt and working capital equal to 1% of EPC costs. The NYSERDA estimate, as we have confirmed through discussion with NYSERDA staff, accounts for financing costs and working capital separately from capital costs, and therefore the base case capital cost estimate does not include financing costs and working capital. Added together, these three costs account for approximately \$265/kW of the difference between the ISO proposal and the NYSERDA estimate. This hardly explains the \$2,203/kW gap between the NYSERDA base case cost estimate of \$3,155/kW and the ISO's cost estimate of \$5,358/kW. These three costs account for approximately \$138/kW of the difference between the NEPOOL Alternative and the NYSERDA estimate. Adding \$138/kW to the NYSERDA value would bring it to \$3,293/kW, which is exceptionally close to the NEPOOL Alternative value of \$3,326/kW.

Response to CEA's Comments

The ISO, in its November 30 memo to the NEPOOL Participants Committee, stated "the NYSERDA model does not reflect a 'bottom up' approach.⁸² In addition, the paper itself notes that its base case (used by RENEW) needs to be adjusted to reflect site and technology differences, the details of which are incompletely explained. As a result, the values within that paper may materially underestimate offshore wind resources total costs."

⁸² Karl Mem. at 2 n.3 (page 252 of the PDF).

The detailed breakdown of the capital cost shown in the table above is for NYSERDA's base case project that has a description nearly identical to the reference unit. The purpose of the NYSERDA report was to look at the expected cost of procuring 9,000 megawatts of offshore wind. The report describes that it did this by starting with a base case project, the one discussed above that is nearly identical to the ORTP reference project, and then making a series of adjustments to the base case estimate in order to arrive at the assumed cost of the other 8,200 megawatts of offshore wind projects that would be built to meet the state's goal. The analysis in the report related to the other 8,200 megawatts of offshore wind to be built in other locations at other times is not relevant to the question of what the 800 MW base case project with 2025 COD is expected to cost. No adjustments are needed to the base case cost estimate to account for differences with the ORTP reference unit.

Comparison to Reference Technology

1 0	
Suitability of Benchmark	Potential Reasons for Discrepancy
Excellent	Location (L)

This detailed cost estimate only differs from the ISO's reference technology by location. We believe that the locational differences in costs between the NY Bight and the MA lease area are small. EIA AEO2020 indicates that an offshore wind project in the NY Bight would be expected to cost approximately 0.6% more than a project in the MA lease area. Therefore, we believe this cost estimation is an excellent benchmark for the ISO's analysis.

Publicly Available Offshore Wind Canital Cost Estimates

Specifications	
Title of Report	PPA Analysis of Recent NE Offshore Wind Contracts
Publishing Year	2020
Value (2019\$/kW)	\$3,326
Range (2019\$/kW)	\$2,486-4,021
Size (MW)	400-804
Location	New England
COD	2021–2024
Installed/Overnight	Installed
Source	<u>Link</u>

Overnight Capital Costs (excludes cost of interest during construction)

Daymark PPA

Description

Daymark Energy Advisors (DEA) completed a study for RENEW Northeast using four recently executed Power Purchase Agreements for energy and RECs from offshore wind projects in the MA offshore lease area. The pricing in these executed contracts defines the amount of non-capacity revenue that these projects will receive for their first twenty years of operation. DEA calculated the level of capital cost that could be supported by this contracted revenue under two sensitivities regarding expected capacity market revenues (\$2/kW-mo. and \$6/kW-mo., assuming all of the qualified capacity was able to qualify and clear in all years). In the entire analysis conservative but reasonable assumptions were made. Most of these assumptions are identical to the assumptions used by the ISO in their own analysis. The results for each of the four contracts is shown individually in our figure. The full range of DEA's results from the four contracts and two sensitivities is shown in the NEPOOL column while the NEPOOL Alternative assumption of \$3,326 (the green marker and dashed line) represents the weighted average of the results for the most conservative scenario that assumed \$6/kW-mo. capacity pricing.

Response to CEA's Comments

Based on four competitive PPAs we have reasonable insight into the revenue streams and therefore capital costs that can be supported by projects currently under development in New England. There is uncertainty in the analysis, as there is in a bottom-up cost estimate, but because of the extensive benchmarking that has been done by Boreas Renewables using publicly available data, we believe that the implied capital costs derived by DEA are a reasonable assumption to be used in the ORTP recalculation process.

Comparison to Reference Technology

Suitability of Benchmark	Potential Reasons for Discrepancy					
Excellent	Installed (L)					

This study is specific to the actual offshore wind projects being planned in the same location, in the same approximate timeframe, and with the same project design and scope as the ORTP reference project. The only adjustment that would need to be made to make the results of this study fully comparable to the ISO estimate is to lower the cost to reflect overnight capital cost rather than the full installed cost.

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Publicly Available Offshore Wind Capital Cost Estimates

		5	shaded ban	ds indicate	the year of	expected	Vactual com	mercial operatio	on date	2025	
Specifications		6,000	1.	A [2017	2020					
Title of Report	Integrated Resource Plan	AX(\$6102) 4,000		4	I		1	•	*		I
Publishing Year	2020	· 			Ť.	+	-	11	I		
Value (2019\$/kW)	\$2,894	2,000			1	-	1		Ŧ	·] · ·	1
Range (2019\$/kW)	N/A	Capit 000,1 Capit									
Size (MW)	852 MW	0									
Location	Virginia		Car iso	150,12	1802	Land I	Day Pin	11, NR. 03	Desma the	Car do do We had	10000
COD	2026–27		ind	6-20134	2018-	-010*	Stat at	Vine	A. Vine Revo	015, 020, 018, 019, AB,	87. V.
Installed/Overnight	Overnight							and D.	and ID.	on D.	
			Publicly	Available	Data (Err	or Bars s	how cited 1	anges) I	SO's Proposal		
Source	<u>Link</u>	-	Outdated Other ISO	Data Os				N	EPOOL Alterna Cost Trendline	ative	
		*Installed Ca	pital Costs	5							

Dominion



Description

In their Integrated Resource Plan, Dominion listed their capital cost expectation of \$2,952/kW (2020\$) for their commercial-scale offshore wind projects. Based on the EIA AEO2020 report, offshore wind capital costs in Virginia should be approximately 4% higher than capital costs in New England. Therefore, we would expect that a New England project's capital costs would be slightly less than those of a project in Virginia. The Dominion IRP's cited capital cost is thirteen percent less than the cost assumption in the NEPOOL Alternative, demonstrating both the reasonableness and conservatism of the value being proposed by NEPOOL.

Response to CEA's Comments

We agree with CEA's observation that all three projects Dominion is developing are to be located in Virginia. To the extent that there are cost differences between these locations, New England is generally expected to be the lower cost region for building an offshore wind plant. However, we believe the cost differences between the mid-Atlantic and ISO-NE are small enough that this project can be used as a reasonable benchmark for the ISO's reference technology.

Comparison to Reference Technology



To adjust the Dominion number to be directly comparable to the reference unit, one would need to account for regional differences and technological differences. For regional differences one would likely have to adjust the value down because capital costs for offshore wind are lower in New England than in Virginia and one would likely have to adjust the value up to account for Dominion's project having a slightly larger nameplate and a slightly later COD. However, because this project is close in specification, location, and COD and is coming directly from a developer, we believe it to be a reasonable benchmark for the reference unit.

Appendix B to Attachment N-1b

APPENDIX B – RESPONSE TO CEA CRITIQUES OF OFFSHORE WIND ORTP ANALYSIS

Below I respond in more detail to the CEA critique of the offshore wind analysis discussed in the main body of my testimony.

<u>Argument #1: "Winner's Curse"</u>: CEA has multiple times suggested that a project's contract revenue cannot be used to accurately imply its capital cost because it is possible that the developer, either knowingly or unknowingly, signed a contract that will not cover its costs, committing the project to a net financial loss. They have theorized that this might be done knowingly to obtain "first mover advantage" or might be done unknowingly by underestimating costs or overestimating revenues.

CEA's "winner's curse" argument is not well-founded, because it assumes more than is warranted under the circumstances. Modifying Daymark's discounted cash-flow model shows that if the ISO's installed cost assumption were true, the projects with recently signed contracts evaluated by Daymark would have signed themselves up to lose on average approximately \$1.3 billion (2025\$) per 800 MW of offshore wind. We do not assume capacity revenue in these estimates because none of the projects would clear in the FCA if they were required to use the ISO's capital cost assumption in the ISO's offer floor price calculation.

The following table shows the resulting net present value ("NPV") for the projects using the ISO's installed cost assumption and the revenues that these projects would actually receive from the PPAs they have signed plus a 5-year merchant tail.

Project	NPV (2025\$ per 800 MW)
Vineyard Wind I + II	-\$1,248,962,491
Revolution Wind	-\$933,073,838
Mayflower Wind	-\$1,760,642,451

If there were a single offshore wind contract executed by a single developer with pricing that was out of the range of industry expectations, then it might be appropriate to view it as suspect for purposes of implying the project's capital cost, for all of the possible reasons cited by CEA. However, the Daymark analysis does not rely on a single project contracted by a single developer. Rather, Daymark evaluated three projects with four PPAs coming from three competing developers. The developers behind these projects are well-regarded companies with a wealth of experience in offshore wind development. Vineyard Wind is a joint venture of Avangrid Renewables and Copenhagen Infrastructure Partners. Revolution Wind is a joint venture of EVP Renewables and ENGIE. It is highly unlikely and not commercially reasonable to assume that every one of these developers would *knowingly* commit

to losses averaging \$1.3 billion per 800 MW project to gain some kind of first mover advantage. It is also highly unlikely and not commercially reasonable to assume that all of these developers *unknowingly* underestimated their costs by nearly forty percent. Given these circumstances, the CEA assumption about "winner's curse" does not stand up.

<u>Argument #2: New York PPAs Are Evidence of Higher Offshore Wind Costs</u>: CEA pointed to three recent PPAs signed by New York projects with significantly higher first-year prices than the Vineyard Wind PPAs as evidence that Vineyard Wind's PPA price, and therefore the Daymark analysis, is not reflective of the full cost of building an offshore wind project in the Northeast. CEA appears to have misunderstood that the Daymark analysis was not limited to the two Vineyard Wind PPAs but rather included PPAs for two other New England projects as well, representing a range of first year contract prices of \$65/MWh to \$98.425/MWh.

The first New York PPA that CEA cited is for Empire Wind, a project under development by Equinor and BP, with a first year PPA price of \$99.08/MWh. This PPA, signed in October 2019, is for an 816 MW project with a 2024 COD, which is generally comparable to the ORTP reference project. The contract price is an all-in value for energy, RECs, and capacity. Because this contract includes an additional product not included in the New England PPAs, it would make sense that the contract price is higher. On a per MWh basis, the Daymark model includes just over \$8/MWh in first-year capacity revenues in the \$6/kW-month scenario. Adding this \$8/MWh capacity revenue to the energy and REC PPA prices evaluated in the DEA analysis results in total first year revenues of between \$73/MWh and \$106/MWh for the New England projects. The Empire Wind PPA price falls well within this range, which we interpret to be yet another example that further supports the implied capital cost range found in the Daymark analysis.

Further, the Empire Wind PPA was a result of NYSERDA's first offshore wind RFP. The actual bids from that RFP are the ones that were used by the NY DPS and NYSERDA to benchmark the base case offshore wind cost estimate in their recent whitepaper included in our literature review and discussed above. That whitepaper showed a total installed cost of \$3,155/kW, which is five percent lower than the NEPOOL Alternative assumption of \$3,326/kW. This supports our contention that the Empire Wind project further corroborates the implied capital cost range found in the Daymark analysis.

The second New York PPA cited by CEA, with a first year price of \$160/MWh, was a contract signed in 2017 by the Long Island Power Authority and the South Fork wind project now being developed by Eversource and Ørsted. At the time this contract was signed, this project with an expected commercial operations date of 2022 was to be the second offshore wind demonstration project in the nation, at a PPA price that was less than half of the prior Block Island Wind Farm. In 2018, the Long Island Power Authority ("LIPA") and South Fork signed a

second PPA for an additional 40 MW from this project at a first year price of \$86/MWh, the third PPA cited by CEA. As CEA pointed out, it is not appropriate to compare the cost of a demonstration project with the projected cost of a commercial scale project such as the ORTP reference project. These three New York PPAs can be seen in the figure below prepared by LIPA that aimed to reflect the South Fork PPA price in the context of the maturing offshore wind industry.⁸³



*Levelized cost of electricity describes the estimated energy, capacity, and renewable attributes over the period of the contract in 2018 dollars, using a 6.5% discount rate. *LCOE of the combined 130MW South Fork project is 14.1¢. *Revolution Wind's Connecticut contracts are not yet available; price based on Rhode Island contract.

The two South Fork PPAs are shown by the green dots while the Empire Wind PPA is shown by the second blue dot from the right. The Vineyard Wind PPA and the Revolution Wind PPA are also shown in the figure. The Mayflower Wind PPA which is more recent is not shown in this figure. Note that this figure depicts only the PPA prices and does not adjust for the different products purchased by the New York versus New England PPAs. The New York PPA prices shown in the figure reflect the full revenue available to the project. The New England PPAs reflect only energy and REC revenues, while capacity revenues would be an additional revenue stream available to these projects.

⁸³ Long Island Power Auth., South Fork Wind Farm Fact Sheet, at 3, <u>https://www.lipower.org/wp-content/uploads/2019/10/LIPA-First-Offshore-Wind-Farm-Doc-V19_102819-FINAL.pdf</u> (last accessed Mar. 24, 2021).

<u>Argument #3: EIA Projects a LCOE That Exceeds the PPA Prices</u>: CEA further supports its hypothesis that the projects included in the Daymark analysis may have, either knowingly or unknowingly, signed contracts that would result in a financial loss by presenting EIA's LCOE for an offshore wind project beginning operation in 2025 of between \$102.68/MWh and \$155.55/MWh with an average of \$122.25/MWh (2019\$). CEA points out that if the true Vineyard Wind LCOE was actually closer to the higher end of the EIA range, \$160/MWh, that the implied capital cost would more than double from the Daymark findings.

CEA either does not understand or has mischaracterized the cited EIA LCOE numbers as a range of costs applicable to New England. These numbers reported by the EIA do not represent a range of expected LCOEs for offshore wind projects to be built in New England, but rather represent the range of regional variation in expected LCOE across each of the modeled regions of the United States. The EIA's "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020,"84 where these numbers are found, reports that the LCOE can vary significantly by region of the country, due to regional variation in factors such as capital cost and capacity factor. The EIA projection of regional variation in capital costs projects that the offshore wind capital cost in southern New England is among the lowest in the country. EIA projects that only two of fifteen regions would have lower capital costs than southern New England: Texas (approximately 2.4% lower) and the Carolinas (approximately 10% lower). With respect to capacity factor, the marginal site EIA modeled in each region ranged from 41% to 50%. The ORTP reference project has an assumed capacity factor of 47%, falling at the high end of this range. EIA reports that the minimum regional LCOE for new offshore wind, associated with low capital cost and high capacity factor, is \$102.68/MWh while the maximum regional LCOE for new offshore wind is \$155.55/MWh. EIA has confirmed to me that the \$102.68/MWh LCOE value, at the low end of the range listed in their report, corresponds to region 7 - NPCC/New England. While CEA was correct that if the Vineyard Wind LCOE were closer to \$160/MWh then the implied capital cost in the Daymark model would more than double, there is nothing in the EIA report that supports such an LCOE for New England projects.

As noted above, after adding \$6/kW-month of assumed capacity revenue to the energy and REC PPA prices, the projects in Daymark's analysis had total first year revenues of between \$73/MWh and \$106/MWh. The EIA LCOE of \$102.68/MWh for New England is within this range and further corroborates the Daymark findings.

⁸⁴ U.S. Energy Info. Admin., *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020* (Feb. 2020), <u>https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf</u>.

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Even the contract with the highest first year contract price included in the Daymark analysis that was above the EIA's LCOE estimate for the New England region, providing total first year revenue of \$106/MWh, had an implied capital cost of \$3,722/kW in the Daymark analysis. The ISO's proposed capital cost assumption of \$5,358/kW remains 44% higher than Daymark's value, indicating that it is not a reasonably accurate estimation of capital costs for offshore wind.

<u>Argument #4: NREL's Analysis of Vineyard Wind PPA Identifies LROE Higher than</u> <u>PPA Price</u>: Lastly, CEA cited the NREL analysis of the Vineyard Wind PPA that was included in our literature review, which determined that the expected Levelized Revenue of Energy ("LROE") for the Vineyard Wind project was \$98/MWh (2018\$).⁸⁵ The implication, as we understand CEA's argument, is that the Vineyard Wind PPA price used in the Daymark analysis somehow underestimates the total revenue available to this project and therefore the Daymark analysis underestimated the capital cost that could be supported by the PPA.

To calculate the LROE of \$98/MWh NREL started with the PPA revenue, as did Daymark. They then accounted for the value of the Investment Tax Credit, as did Daymark. Next, NREL added capacity market revenue assuming 38% of the project would receive a capacity price of \$5/kW-month escalating at 2.5% per year. Daymark also added capacity revenue, using a higher initial capacity price earned by a greater percentage of the project: \$6/kW-month capacity price escalating at 2% per year while assuming, as ISO does, that 46% of the project would qualify for capacity revenue. NREL then adjusted for dollar years to 2018\$ while Daymark adjusted to 2019\$.⁸⁶ In short, the Daymark analysis included all of the revenues that were included in the NREL analysis, with somewhat higher capacity revenues.

<u>Conclusion</u>: The comparisons CEA made between the Daymark analysis and PPAs in New York, EIA's LCOE projections, and the NREL analysis of the Vineyard Wind PPA, when examined carefully, corroborate the validity of the Daymark analysis. A June 2020 paper published by NREL, "Comparing Offshore Wind Energy Procurement and Project Revenue Sources Across U.S. States,"⁸⁷ finds that analyses such as these are valid approaches to validating expected project costs. The paper states that "a comprehensive accounting of expected project revenue can serve as a critical reference point for validating bottom-up cost modeling estimates of U.S. offshore wind projects, which, to date, have made limited cost and experience

⁸⁵ Philipp Beiter, et al., *The Vineyard Wind Power Purchase Agreement: Insights for Estimating Costs of U.S. Offshore Wind Projects*, Nat'l Renewable Energy Lab., at 7 (Feb. 2019), https://www.nrel.gov/docs/fy19osti/72981.pdf.

⁸⁶ *Id.* at 5–7.

⁸⁷ Philipp Beiter, et al., *Comparing Offshore Wind Energy Procurement and Project Revenue Sources Across U.S. States*, Nat'l Renewable Energy Lab. (June 2020), <u>https://www.nrel.gov/docs/fy20osti/76079.pdf</u>.

data available."⁸⁸ The Daymark analysis, which is based upon actual contractual commitments made by a variety of competing developers, when viewed alongside the extensive literature review that converges with the Daymark findings, is truly the best available indication of prevailing industry and market expectations.

Attachment N-1c

Testimony of Carolyn Gilbert

UNITED STATES OF AMERICA BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.

Docket No. ER21-___-000

TESTIMONY OF CAROLYN GILBERT

1 I. Introduction

- 2 Q: Please state your name and business address.
- A: My name is Carolyn Gilbert. My business address is 370 Main Street, Suite 325, Worcester,
 MA 01608.

5 Q: By whom are you employed and in what capacity?

6 A: I am employed by Daymark Energy Advisors (Daymark). Daymark provides integrated 7 policy, planning, and strategic decision support services to the North American electricity 8 and natural gas industries. Daymark serves a diverse clientele from our office in Worcester, 9 Massachusetts by providing consulting services to organizations involved with energy 10 markets, including renewable energy producers, private and public utilities, transmission 11 owners, energy producers and traders, energy consumers and consumer advocates, 12 regulatory agencies, and public policy and energy research organizations. Our technical 13 skills include cost allocation, rates and pricing, power market forecasting models and 14 methods, economics, management, planning, energy procurement, contracting and 15 portfolio management, and reliability assessments. Our experience includes detailed 16 analyses of energy and environmental performance of electric systems, economic planning 17 for transmission and distribution, and market analytics.

-1-

1 **Q:**

Please describe your current responsibilities.

- A: I am a Managing Consultant for Daymark. I am an expert in state and regional renewable
 resource development, economics, and policy. My work focuses on renewable project
 development and economics, value of distributed energy resources, asset valuation,
 competitive resource procurement, such as offshore wind projects.
- 6 Q: Prior to joining Daymark, where did you work and what were your responsibilities?
- A: Prior to joining Daymark, I held positions as a research analyst at the Tellus Institute, an
 environmental engineer at Camp Dresser and McKee, and as an independent consultant
 working on renewable energy issues.
- 10 Q: Please describe your education and professional background.
- A: I received my B.A. in Engineering Sciences and Environmental Earth Sciences from
 Dartmouth College and received a B.E. in Engineering from the Thayer School of
 Engineering at Dartmouth. I received my M.B.A. from the Ross School of Business at the
 University of Michigan.
- 15 Q: Have you previously testified in regulatory proceedings?
- 16 A: Yes. I have testified before the Utilities Commissions in Arkansas, North Carolina,
 17 Georgia, Maryland, and Rhode Island. My appearances are included in Appendix A to this
 18 testimony.
- 19 Q: In what capacity are you submitting this affidavit?
- A: I submit this affidavit in my capacity as a Senior Consultant at Daymark, who was engaged
 by the New England Power Pool (NEPOOL), to offer testimony in support of the NEPOOL
 Alterative in the above-captioned proceeding, which relies, in part, to an analysis that

Attachment N-1c – Testimony of Carolyn Gilbert

Daymark conducted on behalf of RENEW Northeast regarding the overnight capital costs
 of offshore wind projects.

3 Q: What is the purpose of your affidavit?

- 4 A: The purpose of my affidavit is to explain my analysis of four recently executed offshore
- 5 wind Power Purchase Agreements (PPAs) in New England and the results of the analysis.
- 6 For simplicity sake, I will refer to my work as the "Daymark Analysis."

7 II. <u>Summary of the Daymark Analysis</u>

8 Q: Please provide a high-level overview of the Daymark Analysis.

9 A: The purpose of the analysis was to calculate the implied capital costs that could be

10 supported by the expected revenues for three offshore wind projects in New England using

11 publicly available PPA pricing to estimate the projects' revenues.¹ The PPAs will provide

¹ Offshore Wind Generation Unit Power Purchase Agreement Between Fitchburg Gas and Electric Light Company d/b/a Unitil and Mayflower Wind Energy LLC (Jan. 10. 2020) https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11796510 (providing, in Exhibit D and are pages 75–76 of 84, the pricing information for Mayflower Wind PPA Phase I); Offshore Wind Generation Unit Power Purchase Agreement Between Fitchburg Gas and Electric Light Company d/b/a Mayflower Wind Unitil and Energy LLC (Jan. 10. 2020) https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11796526 (providing, in Exhibit D and are pages 74–75 of 83, the pricing information for the Mayflower Wind PPA Phase II). These PPAs were filed with the Massachusetts Department of Public Utilities ("MA DPU") in Docket D.P.U. 20-16/20-17/20-18 and are Exhibits JU-3-G and JU-3-H, respectively.

Offshore Wind Generation Unit Power Purchase Agreement Between the Narragansett Electric Company, d/b/a National Grid, as Buyer and DWW REV I, LLC as Seller (Dec. 6, 2018), <u>http://www.ripuc.ri.gov/eventsactions/docket/4929-NGrid-PPA-NG-1.pdf</u> (providing, in Exhibit D and is page 67 of 70, the pricing information for Revolution Wind Tranche 1). This PPA was filed with the Rhode Island Public Utilities Commission in Docket 4929.

Offshore Wind Generation Unit Power Purchase Agreement Between NSTAR Electric Company d/b/a Eversource Vineyard LLC 2018) Energy and Wind (July 31. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9676522 (providing, in Exhibit D and are pages 71–72 of 77, the pricing information for Vineyard Wind Tranche 1); Offshore Wind Generation Unit Power Purchase Agreement Between Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid and Vineyard Wind LLC (Julv 31. 2018). https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9676525 (providing, in Exhibit D and are page 78-80 of 85, the pricing information for Vineyard Wind Tranche 2). These PPAs were filed with the MA DPU in Docket D.P.U. 18-76/18-77/18-78 and are Exhibits JU-3-A and JU-3-D, respectively.

Attachment N-1c – Testimony of Carolyn Gilbert

1 the vast majority of expected revenue for these projects. I developed a financial model to 2 calculate the capital costs that could be supported by the contracted PPA revenues and a 3 reasonable expectation of revenue from ISO-NE's capacity market. The model is included 4 as Appendix B to my testimony.

5

Why did you choose to analyze recently executed PPAs? **O**:

6 A: Recently executed offshore wind PPAs in New England offer the best source of 7 information for expected offshore wind capital costs in this region. A rational project 8 developer will only execute an agreement for the sale of power from a project that allows 9 it to cover its costs including debt service and provide investors with their required return. 10 These PPAs, therefore, provide insight into the amount of revenue an offshore wind 11 developer would have expected to need to recover its costs and provide a return to 12 investors. Thus, these publicly available PPAs reflect the most recent commercial 13 expectations and commitments for offshore wind projects, and the model I developed uses 14 these PPAs as a foundation to determine the capital costs that could be supported by these 15 revenue streams.

16

Q: What offshore wind PPA's were evaluated in the Daymark Analysis?

The offshore wind projects are detailed in the following table. These contracts are the four 17 A: 18 most recent publicly available contracts for offshore wind projects currently under 19 development in New England, whose analysis reflects expected prevailing market conditions. 20

Project	Capacity (MW)	State RFP	Selection Date	COD Expectation at PPA Execution	First Year PPA Price
Vineyard Wind Tranche 1	400	MA	May 2018	2021	\$74/MWh (escalating 2.5% annually)
Vineyard Wind Tranche 2	400	MA	May 2018	2022	\$65/MWh (escalating 2.5% annually)
Revolution Wind Tranche 1	400	RI	May 2018	2023	\$98.25/MWh (Fixed for contract term)
Mayflower Wind	804	MA	October 2019	2024	\$77.76/MWh (Fixed for contract term)

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1 Q: Please describe the financial model that you developed.

A: As I understand it, the ISO determines the Offer Review Trigger Price (ORTP) for new
resources by calculating the implied revenue required from the Forward Capacity Market
in order for a new generator to have a net present value of zero given a set of assumptions
about all other components of the project's financial model. When ISO-NE develops an
ORTP for a hypothetical project, the capital costs should be set at expected prevailing
market conditions. Thus, the ISO's ORTP model solves for the capacity revenue needed,
given a fixed assumption about a project's cost.

9 With this background in mind, my financial model, as presented in Appendix B that is 10 attached to this testimony, solves for the project cost given a fixed assumption about 11 capacity revenue. The underlying structure of my model is the same as the ISO's model. It 12 simply solves for a different variable. Specifically, the financial model was developed to 13 calculate the implied capital costs of New England offshore wind projects given a fixed set 14 of assumptions regarding a project's capacity revenue.

Where appropriate, I used the same input assumptions in my model as the ISO's ORTP model. Where my assumptions differed from the ISO's, I took a conservative approach when appropriate by using assumptions that would increase the implied capital costs. Based on my experience, all of the assumptions that I used in my model reflect reasonable

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Attachment N-1c – Testimony of Carolyn Gilbert

assumptions that offshore wind developers would take at the time when these developers
 submitted the bids that resulted in the contracts that were studied as part of this analysis.

3 Q: What assumptions differed between the Daymark Analysis and the ISO's model, and
4 what effect does that have on the implied capital cost?

5 A: My model used the following six assumptions, which differed from the ISO's. Generally, 6 these assumptions increased the revenues that the project would be expected to receive, which in 7 turn would increase the implied capital costs that the project could support. For these reasons, I 8 consider these assumptions as conservative because a higher capital costs results in a higher ORTP.

- 9
 1. Project Lifetime The ISO model assumes 20 years of operating expenses and
 10 revenues with zero residual value at the end of this term. My model assumed 25
 11 years of operating expenses and revenues. As a result, the offshore wind project's
 12 net revenues were assumed to be increased, which in turn results in a higher implied
 13 capital cost.
- 14 2. Energy and REC revenue in years 1 through 20 – The ISO model makes 15 assumptions regarding energy and Renewable Energy Credit (REC) market prices 16 to determine the project's expected energy and REC revenue. My model uses the 17 actual contracted price for energy and RECs from the project's PPA for the first 20 18 years of project operation. Because the PPA payment rate for energy and RECs for 19 the first 20 years of the projects' operation is fixed by the PPA's terms and is not 20 subject to market volatility or risk, this affords a higher level of certainty in the 21 project revenue used in my model.
- 22 3. Energy and REC revenue in years 21 through 25 The ISO model assumes the
 23 project has no value beyond 20 years. In years 21 through 25, after the PPA contract

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Attachment N-1c – Testimony of Carolyn Gilbert

term has ended, my model assumes the project continues to operate and earn energy
 revenue at an assumed market based rate. The energy market rate assumed for years
 21 through 25 was \$40/MWh in 2022, escalated at 2 percent annually thereafter.
 Even after discounting future years' cash flows, this significantly increases the
 project's expected revenues, which results in a higher implied capital cost.

- 4. Investment Tax Credit (ITC) The ISO model assumes 30 percent ITC eligibility
 for offshore wind projects. My model assumed an 18 percent ITC eligibility for
 Vineyard Wind I and II, as well as Revolution Wind, and 12 percent ITC eligibility
 for Mayflower Wind. My assumption regarding the ITC was based upon the tax
 law in effect at the time the developers submitted the bids that resulted in the
 analyzed PPAs.
- 12 5. FCM Revenues – Recent offshore wind PPAs in New England do not include 13 capacity as a contracted product. As such, the project retains any capacity revenues 14 it is able to obtain from the market. My model assumed the same quantity of 15 qualified capacity as the ISO's model. Where the ISO model solves for the capacity 16 price needed to achieve a net present value of zero, my model used an assumption 17 about the expected capacity price to solve for the capital cost that would result in a 18 net present value of zero. My financial model studied two sensitivities regarding 19 capacity prices. A low assumption of \$2/kW-month was studied to align with the 20 recent fourteenth Forward Capacity Auction (FCA) clearing price. A high 21 assumption of \$6/kW-month was also studied, reflecting a \$1.086/kW-month 22 premium over the average FCA clearing price in all fifteen auctions held to date. 23 These capacity revenues were modeled to escalate with inflation for the 25 year

Attachment N-1c – Testimony of Carolyn Gilbert

17	0.	What	were the regults from the Dermony Analysis recording the expected conital
16			their bid pricing analysis.
15			reflects the revenue that a project developer might have considered including in
14			vicinity of \$5,455/MWh after FCA 15. Thus, this assumption more accurately
13			2020, it was a reasonably common expectation that the PPR would remain in the
12			PPAs, the PPR in the Tariff for FCA 15 and beyond was \$5,455/MWh. Prior to
11			time that the project developers submitted the bids that resulted in the analyzed
10			\$3,500/MWh through May 2024 and \$5,455/MWh from June 2025 forward. At the
9			calculated and filed by ISO-NE in 2021. My financial model uses the PPR of
8			Performance Payment Rate (PPR) of \$8,894/MWh, the PPR value was re-
7			for-Performance energy and ancillary services (E&AS) offset using an assumed
6		6.	FCM Pay-for-Performance Revenues - The ISO model calculates the FCM Pay-
5			implied capital cost.
4			increased. Assuming lower or no capacity revenue would have resulted in a lower
3			the project's assumed revenues were increased and the implied capital cost in turn
2			projection of capacity prices, i.e., \$6/kW-month, for the full 25 year modeling term,
1			modeled project lifetime. By using what we believe to be an above-market

costs of offshore wind projects in New England and did you present these results during the NEPOOL stakeholder process?

A: I presented the initial Daymark Analysis results at the July 2020 Markets Committee
meeting. At the time, the ISO was finalizing the FCA 16 model assumptions. I updated the
financial model to reflect the changes made by the ISO's finalized modeling assumptions.

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Attachment N-1c – Testimony of Carolyn Gilbert

- 1 My final model was posted with the November 2020 Markets Committee meeting 2 materials.
- As the Daymark Analysis demonstrates, the range of implied project capital costs for the four contracts evaluated under the two capacity pricing scenarios was between \$2,486/kW and \$4,021/kW (2019\$). If one takes only the more conservative capacity pricing scenario, the weighted average of the four contracts is \$3,326/kW. The individual project findings are shown in the following table, where all figures are reported in 2019\$.

Projects	Capacity (MW)	Implied CapEx: \$2 capacity price (2019\$/kW)	Implied CapEx: \$6 capacity price (2019\$/kW)
Vineyard Wind Tranche 1	400	\$3,451	\$3,796
Vineyard Wind Tranche 2	400	\$2,856	\$3,201
Revolution Wind Tranche 1	400	\$3,675	\$4,021
Mayflower Wind	804	\$2,486	\$2,809
Capacity Weighte	d Average	\$2,990	\$3,326

- 8 III. Conclusion
- 9 Q: Does this conclude your affidavit?
- 10 A: Yes.

I declare that the information included in the memorandum is true and correct to the best of my

knowledge and belief.

orogen Collas

Carolyn Gilbert Managing Consultant Daymark Energy Advisors Executed on April 5, 2021

Appendix A to Attachment N-1c



Carolyn Gilbert

Senior Consultant

Carrie Gilbert is an expert in renewable energy policy and planning with over 20 years of consulting experience to decision makers in the energy and environmental sectors. She provides decision support analysis to clients on issues related to renewable energy development and economics, asset valuation, and resource planning. She's an expert in state and regional renewable resource development, economics, and policy and has appeared as an expert witness before regulatory agencies in Arkansas, Maryland, Georgia, North Carolina, and Rhode Island.

INDUSTRY EXPERIENCE

Daymark Energy Advisors | www.daymarkea.com | Portland, ME

Daymark Energy Advisors is a consultancy that bring deep knowledge of energy infrastructure, regulation, and markets to help our clients make well-informed business, capital investment, and policy decisions in the face of uncertainty.

Senior Consultant | 2014–Present Consultant | 2008–2014 Specialist | 2007–2008

Consulting practice includes:

- Distributed energy resources valuation
- Energy infrastructure and asset valuation
- Renewable energy policy and market forecasting
- Renewable energy contracting, and competitive solicitation processes
- Integrated resource planning
- Cost-benefit analysis, economic evaluations, and investment decision support

Independent Consultant | Boston, MA

Consultant | 2006-2007

Consulting practice included:

 Strategy consulting to Emerging Energy Research, Keystone Strategy, and Esty Environmental Partners

Camp Dresser and McKee, Inc. | Cambridge, MA

Environmental Engineer | 2000–2004

Tellus Institute | Boston, MA

Research Analyst | 1998–2000

TESTIMONY, PRESENTATIONS & PUBLICATIONS

FORUM	ON BEHALF OF	MATTER
Rhode Island Public Utilities Commission	Rhode Island Division of Public Utilities and Carriers	Retail Rate Filing and Renewable Docket 5005. March 2020
Rhode Island Public Utilities Commission	Rhode Island Division of Public Utilities and Carriers	Renewable Energy Standard Charge and Reconciliation Filing Docket 4935. March 2020.
Arkansas Public Service Commission	Commission General Staff	Reviewed utility acquisition of Build Own Transfer Solar Facility Docket 19-019-U.
Maryland Public Service Commission	Commission Staff	Transforming Maryland's Electric Grid; prepared report <i>Benefits and Costs of Utility Scale and Behind</i> <i>the Meter Solar Resources in Maryland</i> and presented in a public hearing session. Docket PC44. April 2019.
Rhode Island Public Utilities Commission	Rhode Island Division of Public Utilities and Carriers	Ceiling prices for the Renewable Energy Growth program. Dockets 4774, 4672, 4589-B, and 4536-B. 2015-2018.
Rhode Island Public Utilities Commission	Rhode Island Division of Public Utilities and Carriers	Proposed wind power purchase agreement between National Grid and Copenhagen Wind, LLC. Docket 4574.
Rhode Island Public Utilities Commission	Rhode Island Division of Public Utilities and Carriers	Proposed wind power purchase agreement between National Grid and Champlain Wind, LLC for the Bowers wind project. Docket 4437.
Georgia Public Service Commission	Commission Staff	Georgia Power Company's application for the certification of power purchase agreements for wind resources from Blue Canyon II and Blue Canyon VI wind farms. Docket No. 37854. March 2014.
North Carolina Utilities Commission	Southern Environmental Law Center and Environmental Defense Fund	Review and analysis of the proposed registration of Buck and Lee Steam Stations as Renewable Energy Facilities in Docket Nos: E-7, SUB 939 and E-7, SUB 940 Docket Nos. E-7, sub 939, and E-7, sub 940. June 2010.

Expert Testimony

Industry Leadership

Maine Climate Council | climatecouncil.maine.gov

On June 26, 2019, the Governor and Legislature created the Maine Climate Council, an assembly of scientists, industry leaders, bipartisan local and state officials, and engaged citizens to develop a four-year plan to put Maine on a trajectory to reduce emissions by 45% by 2030 and at least 80% by 2050. By Executive Order of Gov. Mills, the state must also achieve carbon neutrality by 2045.

Member, Energy Working Group | 2019–Present

The Energy Working Group will evaluate and recommend short- and long-term mitigation strategies to reduce gross and net annual greenhouse gas emissions from Maine's energy sector, as well as evaluate and recommend short- and long-term strategies and actions for adaptation and resiliency to climate change.

Invited Speaker & Conference Presentations

- Blueprint for a Zero Carbon Economy: Achieving Maine's Climate Goals, panel moderator for virtual event hosted by the Environmental and Energy Technology Council of Maine (E2Tech), June 2020.
- Energy Storage: Lessons Learned & Opportunities Ahead, moderated panel at Renewable Energy Vermont, October 2018.
- Generation Drivers in New England, presented at the American Wind Energy Association's (AWEA) Wind Energy Regional Conference 2018 – Northeast, June 2018.
- The Role of Large-Scale Renewables in Meeting the Region's Carbon Reduction Targets, presented at the Northeast Energy and Commerce Association's Renewable Energy Conference, February 2018.
- Financing Infrastructure in New England: Can it be done?, moderated panel at the Northeast Energy and Commerce Association and the Connecticut Power and Energy Society's 22nd Annual New England Energy Conference and Exposition, May 2015.
- Incorporating Wind Power in Portfolio Planning, presented at Renewable Energy Vermont, October 2012.
- *New England Renewable Outlook: 2012 at the Crossroads,* presented at the Northeast Energy and Commerce Association's Renewable Energy Conference, February 2012.

Publications

- Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, report prepared for the Maryland Public Service Commission regarding an independent analysis of the benefits and costs of solar within each investor owned utility's service territory. November 2, 2018. Lead author.
- Value of Solar Report, report prepared for the Maryland Public Service Commission regarding an independent assessment of the value of distributed solar in the service territories of the two largest Maryland electric cooperatives, and developing rate design options that facilitate solar development with minimum impact to non-participating ratepayers. February 24, 2017. Lead author.

- The Economic, Utility Portfolio, and Rate Impact of Clean Energy Development in North Carolina, report prepared for the North Carolina Sustainable Energy Association. February 15, 2013. Contributing author.
- NYSERDA's Renewable Portfolio Standard 2013 Program Review Main Tier Evaluation, prepared for the New York State Energy Research and Development Authority. September 2013. Contributing author.
- New York solar study: An analysis of the benefits and costs of increasing generation from photovoltaic devices in New York, prepared for the New York State Energy Research and Development Authority. January 2012. Contributing author.

EDUCATION

- M.B.A. | University of Michigan, Ann Arbor, MI | 2006
- **B.E. Engineering** | Dartmouth College, Thayer School of Engineering, Hanover, NH | 1998
- B.A. Engineering Sciences, Environmental Earth Sciences | Dartmouth College, Hanover, NH | 1997

Appendix B to Attachment N-1c



This workbook documents an analysis that Daymark Energy Advisors conducted for RENEW. The purpose of the analysis was to calculated the Implied Capital Expenditures for 4 offshore wind projects with publicly available PPA pricing.

This workbook contains tabs for general assumptions, revenue assumptions, results, and a 2 tabs for each of the four projects. The project tabs are solved for the CapEx value in cell D7 that makes the Net Present Value (NPV) in cell F42 equal to zero.

DISCLAIMER

The analyses supporting the results presented here involve the use of assumptions and projections with respect to conditions that may exist or events that may occur in the future. Although Daymark Energy Advisors has applied assumptions and projections that are believed to be reasonable, they are subjective and may differ from those that might be used by other economic or industry experts to perform similar analysis. In addition, actual future outcomes are dependent upon future events that are outside Daymark Energy Advisors' control. Daymark Energy Advisors cannot, and does not, accept liability under any theory for losses suffered, whether direct or consequential, arising from any reliance on this presentation, and cannot be held responsible if any conclusions drawn from this presentation should prove to be inaccurate.

Assumptions

Qualifed Capacity % of nameplate (summer)	27%	
Qualifed Capacity % of nameplate (winter)	56%	
Fixed O&M (2025\$)	\$92	
Site leasing 2025\$/MW	\$662	
WACC	6.36%	<corrected atwacc<="" td="" to=""></corrected>
Inflation	2.00%	
Federal Tax Rate	21.00%	
State Tax Rate	8.00%	
Combined Tax Rate	27.30%	

	VW Project 1	VW Project 2	Mayflower	Revolution Wind
Capacity (MW)	400	400	804	400
Qualified Capacity (Summer) (MW)	106.315	106.315	213.69315	106.315
Qualified Capacity (Winter) (MW)	225.59	225.59	453.4359	225.59
Investment Tax Credit (ITC)	18%	18%	12%	18%
Year Online	2022	2023	2025	2024
Capacity Factor	47%	47%	47%	47%

Purple cells updated to match ISO's FCA 16 assumptions (this tab and Results tab). Then each results tab was updated using goal seek to change the NPV to 0 by changing the capex value.

Project Revenue Assumptions

				6		D							
				Cont	ract	Pricing	-	1	(60		nue (Ş/KW-r	nonth)	Energy Revenue Post Contract
Year	VW	Project 1	VV	/ Project	Ma	yflower	Revo	olution Wind	\$2 e	escalating	Ş6 escalatir	ng	1
2022	Ş	74.00	4		Ş	-	Ş	-	Ş	2.00	Ş	6.00	\$ 40.00
2023	Ş	75.85	Ş	65.00	Ş	-	Ş	-	Ş	2.04	Ş	6.12	\$
2024	Ş	77.75	Ş	66.63	Ş	-	Ş	98.43	Ş	2.08	Ş	6.24	\$ 41.62
2025	Ş	79.69	Ş	68.29	Ş	77.76	Ş	98.43	Ş	2.12	Ş	6.37	\$ 42.45
2026	Ş	81.68	Ş	70.00	Ş	77.76	Ş	98.43	Ş	2.16	Ş	6.49	\$ 43.30
2027	Ş	83.72	\$	71.75	Ş	77.76	\$	98.43	Ş	2.21	\$	6.62	\$ 44.16
2028	\$	85.82	\$	73.54	\$	77.76	\$	98.43	\$	2.25	\$	6.76	\$ 45.05
2029	\$	87.96	\$	75.38	\$	77.76	\$	98.43	\$	2.30	\$	6.89	\$ 45.95
2030	\$	90.16	\$	77.26	\$	77.76	\$	98.43	\$	2.34	\$	7.03	\$ 46.87
2031	\$	92.42	\$	79.20	\$	77.76	\$	98.43	\$	2.39	\$	7.17	\$ 47.80
2032	\$	94.73	\$	81.18	\$	77.76	\$	98.43	\$	2.44	\$	7.31	\$ 48.76
2033	\$	97.09	\$	83.21	\$	77.76	\$	98.43	\$	2.49	\$	7.46	\$ 49.73
2034	\$	99.52	\$	85.29	\$	77.76	\$	98.43	\$	2.54	\$	7.61	\$ 50.73
2035	\$	102.01	\$	87.42	\$	77.76	\$	98.43	\$	2.59	\$	7.76	\$ 51.74
2036	\$	104.56	\$	89.60	\$	77.76	\$	98.43	\$	2.64	\$	7.92	\$ 52.78
2037	\$	107.17	\$	91.84	\$	77.76	\$	98.43	\$	2.69	\$	8.08	\$ 53.83
2038	\$	109.85	\$	94.14	\$	77.76	\$	98.43	\$	2.75	\$	8.24	\$ 54.91
2039	\$	112.60	\$	96.49	\$	77.76	\$	98.43	\$	2.80	\$	8.40	\$ 56.01
2040	\$	115.41	\$	98.91	\$	77.76	\$	98.43	\$	2.86	\$	8.57	\$ 57.13
2041	\$	118.30	\$	101.38	\$	77.76	\$	98.43	\$	2.91	\$	8.74	\$ 58.27
2042			\$	103.91	\$	77.76	\$	98.43	\$	2.97	\$	8.92	\$ 59.44
2043					\$	77.76	\$	98.43	\$	3.03	\$	9.09	\$ 60.63
2044					\$	77.76			\$	3.09	\$	9.28	\$ 61.84
2045									\$	3.15	\$	9.46	\$ 63.08
2046									\$	3.22	\$	9.65	\$ 64.34
2047									\$	3.28	\$	9.84	\$ 65.62
2048									\$	3.35	\$	10.04	\$ 66.94
2049									\$	3.41	\$	10.24	\$ 68.28
2050									\$	3.48	\$	10.45	\$ 69.64
2051									\$	3.55	\$	10.66	\$ 71.03

Summary of Results

Results \$2/kW-Month Capacity Revenue

Installation Year	Project	Installat	ion Year	202	19\$	MW
	2021 Vineyard Wind 1	\$	3,591	\$	3,451	400
	2022 Vineyard Wind 2	\$	3,031	\$	2,856	400
	2024 Mayflower	\$	2,745	\$	2,486	804
	2023 Revolution Wind	\$	3,978	\$	3,675	400

Results \$6/kW-Month Capacity Revenue

Installation Year	Project	Installat	ion Year	20	19\$	MW	
	2021 Vineyard Wind 1	\$	3,949	\$	3,796		400
	2022 Vineyard Wind 2	\$	3,397	\$	3,201		400
	2024 Mayflower	\$	3,101	\$	2,809		804
	2023 Revolution Wind	\$	4,352	\$	4,021		400

2019\$ 20-year Contract plus 5-year Merchant Tail

Project	\$2/kW-I	Month Capac	\$6/k\	N-Month Capacit	MW
Vineyard Wind 1 (2021 COD Expectation)	\$	3,500	\$	3,800	400
Vineyard Wind 2 (2022 COD Expectation)	\$	2,900	\$	3,200	400
Revolution Wind 1 (2023 COD Expectation	n \$	3,700	\$	4,000	400
Mayflower (2024 COD Expectation	\$	2,500	\$	2,800	804

Capacity Weighted Averages

	Rounded	Numbers	Raw Numbe	ers
wtd avg	\$	3,168.96	\$	3,158.00
wtd avg for \$2/kW scenario	\$	3,018.96	\$	2,990.01
wtd avg for \$6/kW scenario	\$	3,318.96	\$	3,326.00
	Low		High	
Overall range	\$	2,500	\$	4,000



					2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
VW Project 1	Nominal \$		Contract Year	r 0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
	Nameplate	400																											
	Installed Cost (\$/kW)	\$ 3,591																											
			Annual Energy Production (MWh))	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880
			Net Performance Payment (\$/kW-mo))	0.12	0.12	0.15	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Revenue	Energy (Annual MWh)	1,646,880	Energy Revenue																						\$ 97,887,082	\$ 99,844,824	\$101,841,720	\$103,878,554	\$105,956,125
			PfP Revenue	6	\$ 569,775	\$ 569,775	\$ 728,905	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035
			Contract Revenue	8	\$ 121.869.120	\$ 124,915,848	\$ 128.044.920	\$ 131,239,867	\$ 134,517,158	\$ 137.876.794	\$ 141.335.242	\$ 144.859.565	\$ 148,482,701	\$ 152.204.650	\$ 156.008.942	\$159,895,579	\$163,897,498	\$167,998,229	\$172,197,773	\$176,496,130	\$180,909,768	\$185,438,688	\$190.066.421	\$194,825,904	S -	s -	s -	s -	S -
	Qualifed Capacity (summer)	106.315	Capacity Revenue (summer))	\$ 850,520	\$ 867.530	\$ 884.881	\$ 902.579	\$ 920.630	\$ 939.043	\$ 957.824	\$ 976.980	\$ 996.520	\$ 1.016.450	\$ 1.036,779	\$ 1.057.515	\$ 1.078.665	\$ 1.100.238	\$ 1.122.243	\$ 1.144.688	\$ 1.167.582	\$ 1,190,933	\$ 1.214.752	\$ 1.239.047	\$ 1.263.828	\$ 1.289.105	\$ 1.314.887	\$ 1.341.184	\$ 1.368.008
	Qualifed Capacity (winter)	225.59	Capacity Revenue (winter)		\$ 3,609,440	\$ 3,681,629	\$ 3,755,261	\$ 3,830,367	\$ 3,906,974	\$ 3,985,113	\$ 4,064,816	\$ 4,146,112	\$ 4,229,034	\$ 4,313,615	\$ 4,399,887	\$ 4,487,885	\$ 4,577,643	\$ 4,669,196	\$ 4,762,579	\$ 4,857,831	\$ 4,954,988	\$ 5,054,087	\$ 5,155,169	\$ 5,258,273	\$ 5,363,438	\$ 5,470,707	\$ 5,580,121	\$ 5,691,723	\$ 5,805,558
			Total Revenue		\$ 126,898,855	\$ 130,034,782	\$ 133,413,968	\$ 136,860,848	\$ 140,232,798	\$ 143,688,985	\$ 147,245,916	\$150,870,692	\$ 154,596,290	\$ 158,422,750	\$ 162,333,644	\$166,329,014	\$170,441,841	\$174,655,698	\$178,970,631	\$183,386,684	\$187,920,373	\$192,571,744	\$197,324,377	\$202,211,259	\$105,402,383	\$107,492,670	\$109,624,763	\$111,799,497	\$114,017,727
			Levelized Revenue	\$93.5737																									
Expenses			O&M	1	34.807.622	2 35.503.775	36,213,850	36,938,127	37.676.890	38,430,428	39,199,036	39,983,017	40,782,677	41.598.331	42,430,297	43.278.903	44,144,481	45.027.371	45.927.919	46.846.477	47,783,406	48,739,075	49.713.856	50,708,133	51,722,296	52,756,742	53.811.877	54.888.114	55,985,876
			Site Leasing	1	249,338	8 254,325	259,412	264,600	269,892	275,290	280,796	286,412	292,140	297,983	303,942	310,021	316,221	322,546	328,997	335,577	342,288	349,134	356,117	363,239	370,504	377,914	385,472	393,182	401,045
			Property Tax	< 1.0%	2,529,764	4 2,580,359	2,631,966	2,684,605	2,738,298	2,793,064	2,848,925	2,905,903	2,964,021	3,023,302	3,083,768	3,145,443	3,208,352	3,272,519	3,337,969	3,404,729	3,472,823	3,542,280	3,613,125	3,685,388	3,759,096	3,834,278	3,910,963	3,989,182	4,068,966
			Insurance	0.3%	4,308,819	9 4,394,996	4,482,895	4,572,553	4,664,004	4,757,285	4,852,430	4,949,479	5,048,468	5,149,438	5,252,427	5,357,475	5,464,625	5,573,917	5,685,395	5,799,103	5,915,085	6,033,387	6,154,055	6,277,136	6,402,679	6,530,732	6,661,347	6,794,574	6,930,465
					41,895,544	42,733,455	43,588,124	44,459,886	45,349,084	46,256,066	47,181,187	48,124,811	49,087,307	50,069,053	51,070,434	52,091,843	53,133,680	54,196,353	55,280,280	56,385,886	57,513,604	58,663,876	59,837,153	61,033,896	62,254,574	63,499,666	64,769,659	66,065,052	67,386,353
Total Expenses					\$ 41,895,544	\$ 42,733,455	\$ 43,588,124	\$ 44,459,886	\$ 45,349,084	\$ 46,256,066	\$ 47,181,187	\$ 48,124,811	\$ 49,087,307	\$ 50,069,053	\$ 51,070,434	\$ 52,091,843	\$ 53,133,680	\$ 54,196,353	\$ 55,280,280	\$ 56,385,886	\$ 57,513,604	\$ 58,663,876	\$ 59,837,153	\$ 61,033,896	\$ 62,254,574	\$ 63,499,666	\$ 64,769,659	\$ 66,065,052	\$ 67,386,353
Depreciable Plant		91%																											
Depreciation Schedule					20.0%	6 32.0%	19.2%	11.5%	11.5%	5.8%																			
Depreciation					261,401,696	418,242,713	250,945,628	150,567,377	150,567,377	75,283,688	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Basis Net Plant				\$ 1,436,273,053	1,174,871,357	756,628,644	505,683,017	355,115,640	204,548,263	129,264,575	129,264,575	129,264,575	129,264,575	129,264,575	129,264,575	129,264,575	129,264,575	129,264,575	129,264,575	129,264,575	129,264,575	129,264,575	129,264,575						
			Average	252,976,367																									
Operating Income					(176,398,384) (330,941,385)	(161,119,784)	(58,166,415)	(55,683,663)	22,149,231	100,064,729	102,745,882	105,508,983	108,353,697	111,263,210	114,237,171	117,308,161	120,459,345	123,690,350	127,000,798	130,406,769	133,907,868	137,487,224	141,177,363	43,147,809	43,993,004	44,855,104	45,734,445	46,631,373
Income Taxes					(48,156,759)) (90,346,998)	(43,985,701)	(15,879,431)	(15,201,640)	6,046,740	27,317,671	28,049,626	28,803,952	29,580,559	30,374,856	31,186,748	32,025,128	32,885,401	33,767,466	34,671,218	35,601,048	36,556,848	37,534,012	38,541,420	11,779,352	12,010,090	12,245,443	12,485,504	12,730,365
ITC		18%			258,529,150																								
PTC					-	-	-		-	-	-	-	-	-															
Net Income					\$ 130,287,524	\$ (240,594,387)	\$ (117,134,083)	\$ (42,286,984)	\$ (40,482,023)	\$ 16,102,491	\$ 72,747,058	\$ 74,696,256	\$ 76,705,031	\$ 78,773,138	\$ 80,888,354	\$ 83,050,424	\$ 85,283,033	\$ 87,573,944	\$ 89,922,885	\$ 92,329,580	\$ 94,805,721	\$ 97,351,020	\$ 99,953,212	\$102,635,943	\$ 31,368,457	\$ 31,982,914	\$ 32,609,661	\$ 33,248,942	\$ 33,901,008
Plus: Depreciation					261,401,696	418,242,713	250,945,628	150,567,377	150,567,377	75,283,688	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Cash Flow					\$ 391,689,220	\$ 177,648,326	\$ 133,811,545	\$ 108,280,393	\$ 110,085,354	\$ 91,386,179	\$ 72,747,058	\$ 74,696,256	\$ 76,705,031	\$ 78,773,138	\$ 80,888,354	\$ 83,050,424	\$ 85,283,033	\$ 87,573,944	\$ 89,922,885	\$ 92,329,580	\$ 94,805,721	\$ 97,351,020	\$ 99,953,212	\$102,635,943	\$ 31,368,457	\$ 31,982,914	\$ 32,609,661	\$ 33,248,942	\$ 33,901,008
Capital Expenditures				\$ 1,436,273,053																									
Free Cash Flows				\$ (1,436,273,053)) \$ 391,689,220	\$ 177,648,326	\$ 133,811,545	\$ 108,280,393	\$ 110,085,354	\$ 91,386,179	\$ 72,747,058	\$ 74,696,256	\$ 76,705,031	\$ 78,773,138	\$ 80,888,354	\$ 83,050,424	\$ 85,283,033	\$ 87,573,944	\$ 89,922,885	\$ 92,329,580	\$ 94,805,721	\$ 97,351,020	\$ 99,953,212	\$102,635,943	\$ 31,368,457	\$ 31,982,914	\$ 32,609,661	\$ 33,248,942	\$ 33,901,008
Discount Factor		6.36%																											

1

					2																								
					2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
VW Project 2	Nominal \$	100	Contract Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
	Nameplate	400																											
	Installed Cost (\$/KVV)	\$ 3,031	Appual Eporeu Broduction (MM/b)		1 646 990	1 646 990	1 646 990	1 646 990	1 646 990	1 646 990	1 646 990	1 646 990	1 6 4 6 9 9 0	1 646 990	1 646 990	1 646 990	1 6 4 6 9 9 0	1 646 000	1 646 990	1 6 4 6 9 9 0	1 646 990	1 646 990	1 646 990	1 646 990	1 646 990	1 646 990	1 646 990	1 646 990	1 646 00/
			Not Derformence Dermont (\$1/4/1 me)		1,040,000	1,040,000	1,040,000	1,040,000	1,040,000	1,040,000	1,040,000	1,040,000	1,040,000	1,040,000	1,040,000	1,040,000	1,040,000	1,040,000	1,040,000	1,040,000	1,040,000	1,040,080	1,040,000	1,040,000	1,040,080	1,040,000	1,040,000	1,040,000	1,040,000
Bauapua	Enormy (Annual MM/h)	1 646 990	Fineral Perioritance Payment (3/KVV-IIIO)		0.12	0.15	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	C 101 941 720	¢ 102 070 EEA	0.19 0105 056 105	C 102 075 04
Trovorido	Energy (Anindai Wivin)	1,040,000	DfD Revenue		\$ 560 775	\$ 728.005	\$ 888.035	\$ 888.035	\$ 888.035	\$ 888.035	\$ 888.035	\$ 888.035	\$ 888.035	\$ 888.035	\$ 888.035	\$ 999.035	\$ 888.035	\$ 888.035	\$ 888.035	\$ 888.035	\$ 888.035	\$ 888.035	\$ 888.035	\$ 888.035	\$ 999,044,024	\$ 101,041,720	\$ 888.035	\$ 888.035	\$ 888.030
	-		Contract Revenue		\$ 107.047.200	\$ 100 731 614	\$ 112 465 435	\$ 115 281 600	\$ 118 163 640	\$ 121 111 555	\$ 124 141 814	\$ 127 237 040	\$ 130 432 806	\$ 133,603,718	\$ 137.036.885	\$ 140 462 305	\$ 143,970,250	\$ 147 560 448	\$ 151 240 450	\$ 155.037.283	\$ 158 007 451	\$ 162,802,001	\$ 166 060 604	\$ 171 127 301	\$ 000,000	\$ 000,000	\$ 000,000	\$ 000,000	\$ 000,030
	Qualifed Canacity (summer)	106 315	Canacity Revenue (summer)		\$ 867.530	\$ 884 881	\$ 902 579	\$ 920,630	\$ 939.043	\$ 957.824	\$ 976 980	\$ 996 520	\$ 1,016,450	\$ 1,036,779	\$ 1,057,515	\$ 1,078,665	\$ 1100 238	\$ 1 122 243	\$ 1 144 688	\$ 1167 582	\$ 1 190 933	\$ 1 214 752	\$ 1 239 047	\$ 1 263 828	\$ 1 289 105	\$ 1 314 887	\$ 1341184	\$ 1368,008	\$ 1 395 36/
	Qualified Capacity (winter)	225 59	Capacity Revenue (winter)		\$ 3,681,629	\$ 3,755,261	\$ 3,830,367	\$ 3,906,974	\$ 3,985,113	\$ 4,064,816	\$ 4 146 112	\$ 4 229 034	\$ 4313.615	\$ 4 399 887	\$ 4 487 885	\$ 4577.643	\$ 4,669,196	\$ 4762579	\$ 4,857,831	\$ 4 954 988	\$ 5,054,087	\$ 5,155,169	\$ 5 258 273	\$ 5363438	\$ 5,470,707	\$ 5,580,121	\$ 5,691,723	\$ 5,805,558	\$ 5,921,660
		1	otal Revenue		\$ 112,166,134	\$ 115,100,662	\$ 118,086,416	\$ 120,997,239	\$ 123,975,831	\$ 127,022,230	\$ 130,152,942	\$ 133,351,538	\$ 136,650,996	\$ 140.018.420	\$ 143,470,320	\$ 147,006,738	\$ 150,627,719	\$ 154,333,306	\$ 158,140,013	\$ 162,047,888	\$ 166,040,507	\$ 170,150,857	\$ 174,346,049	\$ 178,642,602	\$ 107,492,670	\$ 109,624,763	\$ 111,799,497	\$114,017,727	\$ 116,280,320
			Levelized Revenue	\$82 7179								•						•						1					
																										· · · · ·			
Expenses			O&M		35,503,775	36,213,850	36,938,127	37,676,890	38,430,428	39,199,036	39,983,017	40,782,677	41,598,331	42,430,297	43,278,903	44,144,481	45,027,371	45,927,919	46,846,477	47,783,406	48,739,075	49,713,856	50,708,133	51,722,296	52,756,742	53,811,877	54,888,114	55,985,876	57,105,59
			Site Leasing		254,325	259,412	2 264,600	269,892	275,290	280,796	286,412	292,140	297,983	303,942	310,021	316,221	322,546	328,997	335,577	342,288	349,134	356,117	363,239	370,504	377,914	385,472	393,182	401,045	409,06
			Property Tax	1.0%	2,135,548	2,178,259	2,221,824	2,266,261	2,311,586	2,357,818	2,404,974	2,453,074	2,502,135	2,552,178	2,603,221	2,655,286	2,708,392	2,762,559	2,817,811	2,874,167	2,931,650	2,990,283	3,050,089	3,111,09	3,173,312	3,236,779	3,301,514	3,367,545	3,434,89
			Insurance	0.3%	3,637,372	3,710,119	3,784,322	3,860,008	3,937,208	4,015,953	4,096,272	4,178,197	4,261,761	4,346,996	4,433,936	4,522,615	4,613,067	4,705,328	4,799,435	4,895,424	4,993,332	5,093,199	5,195,063	5,298,964	5,404,943	5,513,042	5,623,303	5,735,769	5,850,48
					41,531,020	42,361,641	43,208,874	44,073,051	44,954,512	45,853,602	46,770,674	47,706,088	48,660,210	49,633,414	50,626,082	51,638,604	52,671,376	53,724,803	54,799,299	55,895,285	57,013,191	58,153,455	59,316,524	60,502,854	61,712,912	62,947,170	64,206,113	65,490,235	66,800,040
																										· · · · · · · · · · · · · · · · · · ·			
																										/			
Total Expenses					\$ 41,531,020	\$ 42,361,641	\$ 43,208,874	\$ 44,073,051	\$ 44,954,512	\$ 45,853,602	\$ 46,770,674	\$ 47,706,088	\$ 48,660,210	\$ 49,633,414	\$ 50,626,082	\$ 51,638,604	\$ 52,671,376	\$ 53,724,803	\$ 54,799,299	\$ 55,895,285	\$ 57,013,191	\$ 58,153,455	\$ 59,316,524	\$ 60,502,854	\$ 61,712,912	\$ 62,947,170	\$ 64,206,113	\$ 65,490,235	\$ 66,800,040
																										'			
Depreciable Plant		91%																								[/]			
Depreciation Schedule					20.0%	32.0%	5 19.2%	11.5%	11.5%	5.8%																			
Depreciation					220,667,231	353,067,569	211,840,541	127,104,325	127,104,325	63,552,162	-	-		-	-	-	-	-	-	-	-	-	-	-	-	<u> </u>	-	-	
Tax Basis Net Plant			\$	\$ 1,212,457,311	991,790,081	638,722,512	426,881,970	299,777,645	172,673,320	109,121,158	109,121,158	109,121,158	109,121,158	109,121,158	109,121,158	109,121,158	109,121,158	109,121,158	109,121,158	109,121,158	109,121,158	109,121,158	109,121,158			/			
			Average	213,554,828																						+/			
Operating Income					(150,032,117)	(280,328,548) (136,962,999)	(50,180,136)	(48,083,005)	17,616,465	83,382,267	85,645,450	87,990,787	90,385,006	92,844,238	95,368,134	97,956,343	100,608,502	103,340,714	106,152,602	109,027,316	111,997,402	115,029,525	118,139,748	45,779,759	46,677,593	47,593,384	48,527,491	49,480,280
Income Laxes		100/			(40,958,768)) (76,529,694) (37,390,899)	(13,699,177)	(13,126,660)	4,809,295	22,763,359	23,381,208	24,021,485	24,675,107	25,346,477	26,035,501	26,742,082	27,466,121	28,212,015	28,979,660	29,764,457	30,575,291	31,403,060	32,252,151	12,497,874	12,742,983	12,992,994	13,248,005	13,508,11/
IIC		18%			218,242,316																								
PIC					-	-	-	-	-	-	-	-	-	-															
Net Income					\$ 109,168,967	\$ (203,798,854) \$ (99,572,100)	\$ (36,480,959)	\$ (34,956,345)	\$ 12,807,170	\$ 60,618,908	\$ 62,264,242	\$ 63,969,302	\$ 65,709,900	\$ 67,497,761	\$ 69,332,634	\$ 71,214,261	\$ 73,142,381	\$ 75,128,699	\$ 77,172,942	\$ 79,262,859	\$ 81,422,112	\$ 83,626,465	\$ 85,887,596	\$ 33,281,884	\$ 33,934,610	\$ 34,600,390	\$ 35,279,486	\$ 35,972,164
Dius: Depresistion					220 667 224	252 067 560	211 940 541	107 104 205	107 104 205	62 552 162																			-
Plus: Depreciation					220,007,231	503,007,009	211,040,041	127,104,325	127,104,325 € 02.147.090	6 76 250 222	E 60 649 009	E 62 264 242	E 62 060 202	£ 65 700 000	E 67 407 764	E 60 222 624	E 74 044 064	e 72 4 42 204	E 75 129 600	E 77 172 042	£ 70.262.950	E 94 400 440	E 92 626 465	¢ 05 007 506	E 22 204 004	E 22 024 640	£ 24 600 200	£ 25 270 496	6 25 072 46
Operating Cash Flow					\$ 323,636,196	÷ 145,266,715		\$ 50,023,366	\$ 52,147,980	a 10,359,333	\$ 00,018,908	⇒ 02,264,242	a 03,969,302	\$ 55,709,900	a 01,497,761	\$ 03,332,634	⇒ 11,214,261	\$ 13,142,381	\$ 10,128,699	ə 11,112,942	÷ 19,262,859	⇒ 01,422,112	ə o3,020,405	a 00,887,596	\$ 33,281,884	ə əə,ə34,610	a 34,000,390	\$ 30,2/9,486	\$ 30,972,164
Conital Exponditures				E 4 242 457 244		1																							+
Fron Cash Flows			3 C	¢ 1,212,407,311 \$ (1,212,407,311)	\$ 320 836 108	\$ 149 268 715	\$ 112 268 441	\$ 00 623 366	\$ 92 147 980	\$ 76 350 333	\$ 60 618 908	\$ 62 264 242	\$ 63 969 302	\$ 65 709 900	\$ 67 497 761	\$ 69 332 634	\$ 71 214 261	\$ 73 142 381	\$ 75 128 699	\$ 77 172 942	\$ 79 262 859	\$ 81 422 112	\$ 83 626 465	\$ 85 887 596	\$ 33 284 884	\$ 33 934 610	\$ 34 600 300	\$ 35 279 486	\$ 35 972 16
1100 00011/10WS	1		•	\$ (1,212,457,311)	9 323,030,130	a 143,200,715	\$ 112,200,441	<i>a</i> 30,023,300	# JL, 147, 500	\$ 10,355,333	\$ 00,310,300	<i>₽</i> 02,204,242	a 03,303,302	\$ 03,709,900	a 01,491,101	00,002,004	φ /1,214,201	a 13,142,301	\$ 13,120,033	<i>a</i> 11,112,342	\$ 13,202,033	φ 01,422,112	\$ 03,320,403	4 03,007,390	\$ 33,201,004	\$ 33,334,010	\$ 34,300,390	<i>↓</i> 33,2/9,400	\$ 33,372,104
Discount Factor	1	6.36%				1																				,			
		0.0070	NPV 25-years	\$0		1																				,			

					3																								
					2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
Mayflower	Nominal \$		Contract Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
	Nameplate	804																											
	Installed Cost (\$/kW) \$	2.745																											
		-	Annual Energy Production (MWh)		3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229
			Net Performance Payment (\$/kW-mo)		0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Revenue	Energy (Annual MWh) 3,310	0,229	Energy Revenue																						\$208,795,894	\$ 212,971,812	\$217,231,248	\$221,575,873	\$226,007,391
			PfP Revenue		\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951
			Contract Revenue		\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$257,403,391	\$257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	s -	S -	S -	S -	s -
	Qualifed Capacity (summer) 213.6	69315	Capacity Revenue (summer)		\$ 1,814,183	\$ 1,850,467	\$ 1,887,476	\$ 1,925,226	\$ 1,963,730	\$ 2,003,005	\$ 2,043,065	\$ 2,083,926	\$ 2,125,605	\$ 2,168,117	\$ 2,211,479	\$ 2,255,709	\$ 2,300,823	\$ 2,346,839	\$ 2,393,776	\$ 2,441,652	\$ 2,490,485	\$ 2,540,294	\$ 2,591,100	\$ 2,642,922	\$ 2,695,781	\$ 2,749,696	\$ 2,804,690	\$ 2,860,784	\$ 2,918,000
	Qualifed Capacity (winter) 453	3.4359	Capacity Revenue (winter)		\$ 7.699.037	\$ 7.853.018	\$ 8.010.078	\$ 8,170,280	\$ 8.333.685	\$ 8,500,359	\$ 8.670.366	\$ 8.843,773	\$ 9.020.649	\$ 9.201.062	\$ 9.385.083	\$ 9,572,785	\$ 9,764,240	\$ 9.959.525	\$ 10,158,716	\$ 10.361.890	\$ 10,569,128	\$ 10,780,510	\$ 10.996.121	\$ 11.216.043	\$ 11,440,364	\$ 11.669.171	\$ 11.902.554	\$ 12,140,606	\$ 12,383,418
		1	fotal Revenue		\$ 268,701,562	\$ 268.891.827	\$ 269,085,896	\$ 269,283,847	\$ 269,485,758	\$ 269,691,706	\$ 269,901,773	\$ 270,116,042	\$ 270.334.596	\$ 270,557,521	\$ 270,784,904	\$271.016.836	\$271,253,405	\$ 271,494,707	\$ 271,740,834	\$ 271,991,884	\$ 272.247.955	\$ 272,509,147	\$ 272,775,563	\$ 273.047.307	\$224,716,990	\$ 229,175,630	\$ 233,723,444	\$238,362,214	\$243.093.759
			Levelized Revenue	\$81.6538																									
Expenses			O&M		74.245.636	75,730,549	9 77.245.160	78,790,063	80.365.864	81,973,181	83.612.645	85,284,898	86,990,596	88,730,408	90,505,016	92.315.116	94,161,419	96.044.647	97,965,540	99.924.851	101.923.348	103.961.815	106.041.051	1 108.161.872	110.325.109	112.531.612	114,782,244	117.077.889	119,419,447
			Site Leasing		531,846	542,483	3 553,333	564,399	575.687	587,201	598,945	610.924	623,142	635,605	648.317	661,284	674,509	688.000	701,760	715,795	730,111	744,713	759.607	7 774,799	790.295	806,101	822.223	838,668	855,441
			Property Tax	1.0%	3.287,683	3.353.437	7 3.420.506	3,488,916	3.558.694	3.629.868	3,702,465	3.776.515	3.852.045	3.929.086	4.007.668	4.087.821	4,169,577	4,252,969	4,338,028	4,424,789	4,513,285	4,603,550	4.695.621	4,789,534	4.885.324	4,983,031	5.082.691	5,184,345	5,288,032
			Insurance	0.3%	6.620.675	6,753,089	6.888.150	7.025.913	7,166,432	7,309,760	7,455,956	7.605.075	7,757,176	7.912.320	8.070.566	8.231.977	8.396.617	8,564,549	8,735,840	8.910.557	9.088.768	9,270,544	9,455,954	9.645.074	9.837.975	10.034,735	10.235.429	10.440.138	10.648.941
					84.685.840	86.379.557	88,107,148	89.869.291	91.666.677	93.500.011	95.370.011	97.277.411	99.222.959	101.207.419	103.231.567	105.296.198	107.402.122	109.550.165	111.741.168	113.975.991	116.255.511	118.580.621	120.952.234	123.371.278	125.838.704	128.355.478	130.922.588	133,541,039	136.211.860
Total Expenses					\$ 84.685.840	\$ 86.379.557	\$ 88,107,148	\$ 89.869.291	\$ 91.666.677	\$ 93,500,011	\$ 95.370.011	\$ 97.277.411	\$ 99.222.959	\$ 101.207.419	\$ 103,231,567	\$105,296,198	\$107,402,122	\$ 109,550,165	\$ 111.741.168	\$ 113.975.991	\$ 116.255.511	\$ 118,580,621	\$ 120.952.234	\$ 123.371.278	\$125,838,704	\$ 128.355.478	\$ 130,922,588	\$133,541,039	\$136.211.860
Depreciable Plant		94%																											
Depreciation Schedule					20.0%	32.0%	6 19.2%	11.5%	11.5%	5.8%																			
Depreciation					414.895.643	663.833.029	398.299.817	238.979.890	238,979,890	119,489,945	-	-	-	-	-		-	-	-	-	-	-		-	-	-		-	-
Tax Basis Net Plant				\$ 2.206.891.719	1.791.996.076	1.128.163.047	729.863.229	490.883.339	251,903,448	132,413,503	132.413.503	132.413.503	132.413.503	132.413.503	132.413.503	132,413,503	132.413.503	132,413,503	132.413.503	132.413.503	132.413.503	132.413.503	132.413.503						
			Average	328,768,325																									
Operating Income					(230.879.921)	(481.320.760)) (217.321.069)	(59,565,334)	(61.160.810)	56,701,750	174.531.762	172.838.631	171.111.636	169.350.102	167.553.337	165,720,637	163.851.283	161.944.542	159.999.666	158.015.893	155,992,444	153.928.526	151.823.329	149.676.029	98.878.286	100.820.152	102.800.856	104.821.174	106.881.899
Income Taxes					(63,030,218)) (131,400,567) (59,328,652)	(16,261,336)	(16,696,901)	15,479,578	47,647,171	47,184,946	46,713,477	46,232,578	45,742,061	45,241,734	44,731,400	44,210,860	43,679,909	43,138,339	42,585,937	42,022,487	41,447,769	40,861,556	26,993,772	27,523,902	28,064,634	28,616,181	29,178,758
ITC		12%			264.827.006		(., .,						., , .		1											., .,
PTC					-	-	-	-	-	-	-	-	-	-															
Net Income					\$ 96.977.303	\$ (349.920.192	\$ (157.992.417)	\$ (43,303,998)	\$ (44,463,909)	\$ 41.222.172	\$ 126.884.591	\$ 125,653,684	\$ 124.398.160	\$ 123,117,524	\$ 121.811.276	\$120,478,903	\$119,119,883	\$ 117,733,682	\$ 116.319.757	\$ 114.877.554	\$ 113,406,506	\$ 111.906.038	\$ 110.375.560	\$ 108.814.473	\$ 71.884.514	\$ 73.296.251	\$ 74,736,223	\$ 76.204.994	\$ 77,703,140
Plus: Depreciation					414.895.643	663.833.029	398.299.817	238.979.890	238.979.890	119,489,945	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-
Operating Cash Flow					\$ 511.872.947	\$ 313,912,837	\$ 240,307,400	\$ 195,675,892	\$ 194,515,982	\$ 160,712,117	\$ 126.884.591	\$ 125.653.684	\$ 124.398.160	\$ 123.117.524	\$ 121.811.276	\$120.478.903	\$119,119,883	\$ 117.733.682	\$ 116.319.757	\$ 114.877.554	\$ 113,406,506	\$ 111.906.038	\$ 110.375.560	\$ 108.814.473	\$ 71.884.514	\$ 73.296.251	\$ 74.736.223	\$ 76.204.994	\$ 77,703,140
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Capital Expenditures				\$ 2.206.891.719																									
Free Cash Flows				\$ (2.206.891.719)) \$ 511.872.947	\$ 313.912.837	\$ 240.307.400	\$ 195.675.892	\$ 194,515,982	\$ 160,712,117	\$ 126.884.591	\$ 125.653.684	\$ 124.398.160	\$ 123,117,524	\$ 121.811.276	\$120.478.903	\$119,119,883	\$ 117.733.682	\$ 116.319.757	\$ 114.877.554	\$ 113,406,506	\$ 111.906.038	\$ 110.375.560	\$ 108.814.473	\$ 71.884.514	\$ 73.296.251	\$ 74.736.223	\$ 76.204.994	\$ 77,703,140
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Discount Factor	6.36	6%																											
			NDV/ 25 years	\$0			1						1	1									1	1					

				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
Revolution Wind	Nominal \$		Contract Year	0 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
	Nameplate	400																										
	Installed Cost (\$/kW)	\$ 3,978																										
			Annual Energy Production (MWh)	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880
			Net Performance Payment (\$/kW-mo)	0.15	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Revenue	Energy (Annual MWh)	1.646.880	Energy Revenue																				:	\$ 101,841,720	\$ 103,878,554	\$ 105,956,125	\$ 108,075,248	\$ 110,236,753
			PfP Revenue	\$ 728,905	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035 \$	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035
			Contract Revenue	\$ 162,094,164	\$ 162,094,164	\$ 162,094,164	\$ 162,094,164	\$ 162,094,164	\$ 162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$ 162,094,164	\$ 162,094,164	\$162,094,164	\$ 162,094,164	\$ 162,094,164	\$ 162,094,164	\$ 162,094,164	\$ 162,094,164	\$ 162,094,164	\$ 162,094,164	\$ 162,094,164 \$	6 -	\$ -	s -	\$-	\$ -
	Qualifed Capacity (summer)) 106.315	Capacity Revenue (summer)	\$ 884,881	\$ 902,579	\$ 920,630	\$ 939,043	\$ 957,824	\$ 976,980	\$ 996,520	\$ 1,016,450	\$ 1,036,779	\$ 1,057,515	\$ 1,078,665	\$ 1,100,238	\$ 1,122,243	\$ 1,144,688	\$ 1,167,582	\$ 1,190,933	\$ 1,214,752 \$	\$ 1,239,047	\$ 1,263,828	\$ 1,289,105	\$ 1,314,887	\$ 1,341,184	\$ 1,368,008	\$ 1,395,368	\$ 1,423,276
	Qualifed Capacity (winter)	225.59	Capacity Revenue (winter)	\$ 3,755,261	\$ 3,830,367	\$ 3,906,974	\$ 3,985,113	\$ 4,064,816	\$ 4,146,112	\$ 4,229,034	\$ 4,313,615	\$ 4,399,887	\$ 4,487,885	\$ 4,577,643	\$ 4,669,196	\$ 4,762,579	\$ 4,857,831	\$ 4,954,988	\$ 5,054,087	\$ 5,155,169 \$	\$ 5,258,273	\$ 5,363,438	\$ 5,470,707	\$ 5,580,121	\$ 5,691,723	\$ 5,805,558	\$ 5,921,669	\$ 6,040,102
			Total Revenue	\$ 167,463,212	\$ 167,715,144	\$ 167,809,803	\$ 167,906,355	\$ 168,004,839	\$ 168,105,291	\$168,207,753	\$168,312,264	\$168,418,866	\$ 168,527,599	\$ 168,638,507	\$168,751,633	\$ 168,867,022	\$ 168,984,718	\$ 169,104,769	\$ 169,227,220	\$ 169,352,120	\$ 169,479,519	\$ 169,609,465	\$ 169,742,011	\$ 109,624,763	\$ 111,799,497	\$ 114,017,727	\$116,280,320	\$ 118,588,166
			Levelized Revenue	\$102.2449																								
Expenses			O&M	36,213,850	36,938,127	37,676,890	38,430,428	39,199,036	39,983,017	40,782,677	41,598,331	42,430,297	43,278,903	44,144,481	45,027,371	45,927,919	46,846,471	47,783,406	48,739,075	49,713,856	50,708,133	51,722,296	52,756,742	53,811,877	54,888,114	55,985,876	57,105,594	58,247,706
			Site Leasing	259,412	264,600	269,892	275,290	280,796	286,412	292,140	297,983	303,942	310,021	316,221	322,546	328,997	335,577	342,288	349,134	356,117	363,239	370,504	377,914	385,472	393,182	401,045	409,066	417,248
			Property Tax	1.0% 2,802,799	2,858,855	2,916,032	2,974,353	3,033,840	3,094,517	3,156,407	3,219,535	3,283,926	3,349,604	3,416,596	3,484,928	3,554,627	3,625,719	3,698,234	3,772,199	3,847,643	3,924,595	4,003,087	4,083,149	4,164,812	4,248,108	4,333,070	4,419,732	4,508,126
			Insurance	0.3% 4,773,867	4,869,344	4,966,731	5,066,065	5,167,387	5,270,735	5,376,149	5,483,672	5,593,346	5,705,213	5,819,317	5,935,703	6,054,417	6,175,506	6,299,016	6,424,996	6,553,496	6,684,566	6,818,257	6,954,622	7,093,715	7,235,589	7,380,301	7,527,907	7,678,465
				44,049,928	44,930,926	45,829,545	46,746,136	47,681,059	48,634,680	49,607,373	50,599,521	51,611,511	52,643,741	53,696,616	54,770,549	55,865,960	56,983,279	58,122,944	59,285,403	60,471,111	61,680,533	62,914,144	64,172,427	65,455,876	66,764,993	68,100,293	69,462,299	70,851,545
Total Expenses				\$ 44,049,928	\$ 44,930,926	\$ 45,829,545	\$ 46,746,136	\$ 47,681,059	\$ 48,634,680	\$ 49,607,373	\$ 50,599,521	\$ 51,611,511	\$ 52,643,741	\$ 53,696,616	\$ 54,770,549	\$ 55,865,960	\$ 56,983,279	\$ 58,122,944	\$ 59,285,403	\$ 60,471,111	\$ 61,680,533	\$ 62,914,144	\$ 64,172,427	\$ 65,455,876	\$ 66,764,993	\$ 68,100,293	\$ 69,462,299	\$ 70,851,545
Depreciable Plant		91%																										
Depreciation Schedule				20.0%	32.0%	19.2%	11.5%	11.5%	5.8%																			
Depreciation				289,614,576	463,383,322	278,029,993	166,817,996	166,817,996	83,408,998	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Basis Net Plant			9	\$ 1,591,288,881 1,301,674,304	838,290,982	560,260,989	393,442,993	226,624,997	143,215,999	143,215,999	143,215,999	143,215,999	143,215,999	143,215,999	143,215,999	143,215,999	143,215,999	143,215,999	143,215,999	143,215,999	143,215,999	143,215,999						
			Average	280,279,908																								
Operating Income				(166,201,293)) (340,599,104)	(156,049,735	(45,657,776)	(46,494,216)	36,061,614	118,600,380	117,712,744	116,807,354	115,883,858	114,941,891	113,981,085	113,001,062	112,001,439	110,981,824	109,941,817	108,881,009	107,798,985	106,695,321	105,569,583	44,168,887	45,034,504	45,917,434	46,818,022	47,736,621
Income Taxes				(45,372,953)) (92,983,555)	(42,601,578	(12,464,573)	(12,692,921)	9,844,821	32,377,904	32,135,579	31,888,408	31,636,293	31,379,136	31,116,836	30,849,290	30,576,393	30,298,038	30,014,116	29,724,515	29,429,123	29,127,823	28,820,496	12,058,106	12,294,420	12,535,459	12,781,320	13,032,098
ITC		18%		286,431,999																								
PTC				-	-	-	-	-	-	-	-	-	-															
Net Income				\$ 165,603,659	\$ (247,615,549)	\$ (113,448,157	\$ (33,193,203)	\$ (33,801,295)	\$ 26,216,793	\$ 86,222,476	\$ 85,577,165	\$ 84,918,947	\$ 84,247,564	\$ 83,562,755	\$ 82,864,248	\$ 82,151,772	\$ 81,425,047	\$ 80,683,786	\$ 79,927,701	\$ 79,156,494	\$ 78,369,862	\$ 77,567,498	\$ 76,749,087	\$ 32,110,781	\$ 32,740,085	\$ 33,381,974	\$ 34,036,702	\$ 34,704,524
Plus: Depreciation				289,614,576	463,383,322	278,029,993	166,817,996	166,817,996	83,408,998	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Cash Flow				\$ 455,218,235	\$ 215,767,773	\$ 164,581,836	\$ 133,624,793	\$ 133,016,701	\$ 109,625,791	\$ 86,222,476	\$ 85,577,165	\$ 84,918,947	\$ 84,247,564	\$ 83,562,755	\$ 82,864,248	\$ 82,151,772	\$ 81,425,047	\$ 80,683,786	\$ 79,927,701	\$ 79,156,494	\$ 78,369,862	\$ 77,567,498	\$ 76,749,087	\$ 32,110,781	\$ 32,740,085	\$ 33,381,974	\$ 34,036,702	\$ 34,704,524
Capital Expenditures			1	\$ 1,591,288,881															1									
Free Cash Flows				\$ (1,591,288,881) \$ 455,218,235	\$ 215,767,773	\$ 164,581,836	\$ 133,624,793	\$ 133,016,701	\$ 109,625,791	\$ 86,222,476	\$ 85,577,165	\$ 84,918,947	\$ 84,247,564	\$ 83,562,755	\$ 82,864,248	\$ 82,151,772	\$ 81,425,047	\$ 80,683,786	\$ 79,927,701	\$ 79,156,494	\$ 78,369,862	\$ 77,567,498	\$ 76,749,087 \$	32,110,781	\$ 32,740,085	\$ 33,381,974	\$ 34,036,702	\$ 34,704,524
Discount Factor		6.36%																										
1	1	1	NDV/25-yeare	(\$0)	1	1	1	1	1	1					1	1	1	1	1	1		1						

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					2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
VW Project 1	Nominal \$		Contract Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
	Nameplate	400																											
	Installed Cost (\$/kW)	\$ 3,949																											
			Annual Energy Production (MWh)		1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880	1.646.880
			Net Performance Payment (\$/kW-mo)		0.12	0.12	0.15	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Revenue	Energy (Annual MWh)	1,646,880	Energy Revenue																						\$ 97,887,082	\$ 99,844,824	\$ 101,841,720	\$ 103,878,554	\$ 105,956,125
			PfP Revenue		\$ 569,775	\$ 569,775	\$ 728,905	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035
			Contract Revenue		\$ 121,869,120	\$ 124,915,848	\$ 128,044,920	\$ 131,239,867	\$ 134,517,158	\$ 137,876,794	\$ 141,335,242	\$ 144,859,565	\$ 148,482,701	\$ 152,204,650	\$ 156,008,942	\$ 159,895,579	\$ 163,897,498	\$ 167,998,229	\$ 172,197,773	\$ 176,496,130	\$ 180,909,768	\$ 185,438,688	\$ 190,066,421	\$ 194,825,904	s -	s -	\$ -	s -	s -
	Qualifed Capacity (summer)	106.315	Capacity Revenue (summer)		\$ 2,551,560	\$ 2,602,591	\$ 2,654,643	\$ 2,707,736	\$ 2,761,891	\$ 2,817,128	\$ 2,873,471	\$ 2,930,940	\$ 2,989,559	\$ 3,049,350	\$ 3,110,337	\$ 3,172,544	\$ 3,235,995	\$ 3,300,715	\$ 3,366,729	\$ 3,434,064	\$ 3,502,745	\$ 3,572,800	\$ 3,644,256	\$ 3,717,141	\$ 3,791,484	\$ 3,867,314	\$ 3,944,660	\$ 4,023,553	\$ 4,104,024
	Qualifed Capacity (winter)	225.59	Capacity Revenue (winter)		\$ 10,828,320	\$ 11,044,886	\$ 11,265,784	\$ 11,491,100	\$ 11,720,922	\$ 11,955,340	\$ 12,194,447	\$ 12,438,336	\$ 12,687,103	\$ 12,940,845	\$ 13,199,662	\$ 13,463,655	\$ 13,732,928	\$ 14,007,587	\$ 14,287,738	\$ 14,573,493	\$ 14,864,963	\$ 15,162,262	\$ 15,465,507	\$ 15,774,818	\$ 16,090,314	\$ 16,412,120	\$ 16,740,363	\$ 17,075,170	\$ 17,416,673
			Total Revenue		\$ 135,818,775	\$ 139,133,101	\$ 142,694,252	\$ 146,326,738	\$ 149,888,006	\$ 153,537,298	\$ 157,291,195	\$ 161,116,876	\$ 165,047,398	\$ 169,082,880	\$ 173,206,977	\$ 177,419,813	\$ 181,754,456	\$ 186,194,566	\$ 190,740,276	\$ 195,391,722	\$ 200,165,511	\$ 205,061,785	\$ 210,064,219	\$ 215,205,898	\$ 118,656,915	\$ 121,012,293	\$ 123,414,778	\$ 125,865,313	\$ 128,364,858
			Levelized Revenue	\$99.8959																									
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Expenses			O&M		34,807,622	35,503,775	36,213,850	36,938,127	37,676,890	38,430,428	39,199,036	39,983,017	40,782,677	41,598,331	42,430,297	43,278,903	44,144,481	45,027,371	45,927,919	46,846,477	47,783,406	48,739,075	49,713,856	50,708,133	51,722,296	52,756,742	53,811,877	54,888,114	55,985,876
			Site Leasing	4.00/	249,338	254,325	259,412	264,600	269,892	275,290	280,796	286,412	292,140	297,983	303,942	310,021	316,221	322,546	328,997	335,577	342,288	349,134	356,117	363,239	370,504	3/7,914	385,472	393,182	401,045
			Property Tax	1.0%	2,782,000	2,838,200	2,894,970	2,952,869	3,011,920	3,072,100	3,133,008	3,190,280	3,200,200	3,325,410	3,391,918	3,409,707	3,528,952	3,599,531	3,071,522	3,744,952	3,819,851	3,890,248	3,974,173	4,053,050	4,134,730	4,217,424	4,301,773	4,387,808	4,475,504
			Insurance	0.3%	42 579 000	4,034,173	4,930,830	5,029,473	0,130,003	0,232,004	47.050.759	3,444,004	0,002,940	5,004,004	51 002 442	52 041 511	54 000 241	6,130,900 EE 090 249	0,203,018	6,3/6,300 57 205 504	6,000,100	50 600 740	0,709,009	62,020,419	62 270 006	7,103,320	7,320,993 65 936 115	67 140 627	7,023,004
					42,370,900	43,430,476	44,299,000	45,165,070	40,000,771	47,010,047	47,930,738	40,909,773	49,007,900	50,005,720	51,903,442	52,841,511	34,000,341	33,080,346	30, 101,933	57,303,394	38,431,700	39,020,740	00,013,133	02,029,410	03,270,000	04,000,400	03,820,115	07,142,037	00,400,490
					-																								
Total Expenses					\$ 42,578,900	\$ 43,430,478	\$ 44,299,088	\$ 45,185,070	\$ 46.088.771	\$ 47.010.547	\$ 47,950,758	\$ 48,909,773	\$ 49,887,968	\$ 50,885,728	\$ 51,903,442	\$ 52,941,511	\$ 54,000,341	\$ 55,080,348	\$ 56,181,955	\$ 57,305,594	\$ 58,451,706	\$ 59,620,740	\$ 60,813,155	\$ 62,029,418	\$ 63,270,006	\$ 64,535,406	\$ 65.826.115	\$ 67,142,637	\$ 68,485,490
					•	•,		•	• •••••••••	•,•,•			• ••••••••		• • • • • • • • • • •	t enjerijeri	• • • • • • • • • • • • • • • • • • • •					• •••	• •••,•••,•••	• •=,•=•,•••		+		• • • • • • • • • • • • • • • • • • • •	
Depreciable Plant		91%																											
Depreciation Schedule					20.0%	32.0%	19.2%	11.5%	11.5%	5.8%																			
Depreciation					287,522,695	460,036,312	276,021,787	165,613,072	165,613,072	82,806,536	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Basis Net Plant				\$ 1,579,795,026	1,292,272,332	832,236,020	556,214,233	390,601,161	224,988,088	142,181,552	142,181,552	142,181,552	142,181,552	142,181,552	142,181,552	142,181,552	142,181,552	142,181,552	142,181,552	142,181,552	142,181,552	142,181,552	142,181,552						
			Average	278,255,451																									
Operating Income					(194,282,820)	(364,333,689)	(177,626,623)	(64,471,404)	(61,813,837)	23,720,215	109,340,437	112,207,104	115,159,430	118,197,152	121,303,535	124,478,303	127,754,115	131,114,218	134,558,321	138,086,128	141,713,805	145,441,045	149,251,065	153,176,480	55,386,909	56,476,886	57,588,663	58,722,676	59,879,369
Income Taxes					(53,039,210)	(99,463,097)	(48,492,068)	(17,600,693)	(16,875,178)	6,475,619	29,849,939	30,632,539	31,438,524	32,267,823	33,115,865	33,982,577	34,876,873	35,794,181	36,734,422	37,697,513	38,687,869	39,705,405	40,745,541	41,817,179	15,120,626	15,418,190	15,721,705	16,031,290	16,347,068
ITC		18%			284,363,105																								
PTC					-	-	-	-	-	-	-	-	-	-															
Net Income					\$ 143,119,495	\$ (264,870,592)	\$ (129,134,555)	\$ (46,870,711)	\$ (44,938,660)	\$ 17,244,596	\$ 79,490,498	\$ 81,5/4,564	\$ 83,720,905	\$ 85,929,330	\$ 88,187,670	\$ 90,495,726	\$ 92,877,241	\$ 95,320,036	\$ 97,823,899	\$ 100,388,615	\$ 103,025,936	\$ 105,735,640	\$ 108,505,524	\$ 111,359,301	\$ 40,266,283	\$ 41,058,696	\$ 41,866,958	\$ 42,691,385	\$ 43,532,301
Diver Democription					007 500 005	400.000.040	070 004 707	405 040 070	405 040 070	00.000 500																			
Plus: Depreciation					287,522,095	400,030,312	2/0.021./0/	100,013,072	100,013,072	62,000,030 € 400 0E4 432	£ 70 400 409	C 04 574 564	£ 92 720 005	E 95 020 220	£ 00 407 670	E 00 405 726	E 02 977 244	E 05 220 026	E 07 922 900	£ 100 200 C1E	£ 102 025 026	£ 405 725 640	£ 109 E0E E24	£ 444 250 204	E 40 266 292	£ 41 059 606	E 44 966 059	E 42 604 295	E 42 522 204
Operating Cash Flow					\$ 430,042,105	\$ 195,165,719	\$ 140,007,232	\$ 110,742,302	\$ 120,074,412	\$ 100,051,132	\$ 75,450,450	\$ 61,574,564	\$ 03,720,905	\$ 65,929,330	\$ 00,107,070	\$ 50,455,726	\$ 52,077,241	\$ 55,320,030	\$ \$1,023,055	\$ 100,300,015	\$ 103,025,936	\$ 105,735,640	\$ 106,505,524	\$ 111,359,301	\$ 40,200,203	\$ 41,050,050	\$ 41,000,950	3 42,091,305	\$ 43,332,301
Capital Expenditures	1		1	\$ 1 579 795 026																									
Free Cash Flows	1			\$ (1 579 795 026	\$ 430 642 189	\$ 195 165 719	\$ 146 887 232	\$ 118 742 362	\$ 120 674 412	\$ 100 051 132	\$ 79 490 498	\$ 81 574 564	\$ 83 720 905	\$ 85 929 330	\$ 88 187 670	\$ 90.495.726	\$ 92 877 241	\$ 95 320 036	\$ 97 823 899	\$ 100 388 615	\$ 103 025 936	\$ 105 735 640	\$ 108 505 524	\$ 111 359 301	\$ 40 266 283	\$ 41 058 696	\$ 41 866 958	\$ 42 691 385	\$ 43 532 301
1100 04011110488				÷ (1,0.3,133,020)		÷	÷	÷	·	÷	÷ . 0,430,430	0.1014,004	÷ 00,720,000	÷ 55,525,550	\$ 55,101,010	÷ 55,-35,720	· · · · · · · · · · · · · · · · · · ·	\$ 00,020,030	÷ 01,020,000	\$ 100,000,010	\$.00,020,000	\$ 100,700,040	÷	÷,000,001	÷ -0,200,200	+ +1,000,000	÷ -1,000,000	÷ -12,001,000	+++++++++++++++++++++++++++++++++++++++
Discount Factor		6.36%																											
			NDV / OF	60							1					1		1			1							1	

					2																								
					2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
VW Project 2	Nominal \$	1	Contract Year	0	1	2024	.3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	2042	2045	22	23	24	25
TTTTTOJOOL2	Nameplate	400	Contrast Four		1	-	0		Ū	0	1	0	5	10		12	10		10	10		10		20			20		
	Installed Cost (\$/kW)	\$ 3,397																					·+						(
	motaliou ooot (entri)	9 3,331	Appual Epergy Production (MWb)		1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880	1 646 880
			Net Performance Payment (\$/kW-mo)		0.12	0.15	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0,19	0.19
Revenue	Energy (Annual MWh)	1.646.880	Energy Revenue	1																			·		\$ 99.844.824	\$ 101.841.720	\$ 103.878.554	\$ 105,956,125	\$ 108.075.248
			PfP Revenue	1	\$ 569,775	\$ 728,905	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035
			Contract Revenue	2	\$ 107,047,200	\$ 109,731,614	\$ 112,465,435	\$ 115,281,600	\$ 118,163,640	\$121,111,555	\$ 124,141,814	\$ 127,237,949	\$ 130,432,896	\$ 133,693,718	\$ 137,036,885	\$ 140,462,395	\$ 143,970,250	\$ 147,560,448	\$ 151,249,459	\$ 155,037,283	\$ 158,907,451	\$ 162,892,901	\$ 166,960,694	\$ 171,127,301	\$ -	s -	\$ -	\$ -	S -
	Qualifed Capacity (summer)	106.315	Capacity Revenue (summer))	\$ 2,602,591	\$ 2,654,643	\$ 2,707,736	\$ 2,761,891	\$ 2,817,128	\$ 2,873,471	\$ 2,930,940	\$ 2,989,559	\$ 3,049,350	\$ 3,110,337	\$ 3,172,544	\$ 3,235,995	\$ 3,300,715	\$ 3,366,729	\$ 3,434,064	\$ 3,502,745	\$ 3,572,800	\$ 3,644,256	\$ 3,717,141	\$ 3,791,484	\$ 3,867,314	\$ 3,944,660	\$ 4,023,553	\$ 4,104,024	\$ 4,186,105
	Qualifed Capacity (winter)	225.59	Capacity Revenue (winter))	\$ 11,044,886	\$ 11,265,784	\$ 11,491,100	\$ 11,720,922	\$ 11,955,340	\$ 12,194,447	\$ 12,438,336	\$ 12,687,103	\$ 12,940,845	\$ 13,199,662	\$ 13,463,655	\$ 13,732,928	\$ 14,007,587	\$ 14,287,738	\$ 14,573,493	\$ 14,864,963	\$ 15,162,262	\$ 15,465,507	\$ 15,774,818	\$ 16,090,314	\$ 16,412,120	\$ 16,740,363	\$ 17,075,170	\$ 17,416,673	\$ 17,765,007
			Total Revenue		\$ 121,264,453	\$ 124,380,947	\$ 127,552,306	\$ 130,652,448	\$ 133,824,144	\$137,067,508	\$ 140,399,126	\$ 143,802,646	\$ 147,311,126	\$ 150,891,753	\$ 154,561,119	\$ 158,319,353	\$ 162,166,586	\$ 166,102,951	\$ 170,145,051	\$ 174,293,026	\$ 178,530,549	\$ 182,890,699	\$ 187,340,688	\$ 191,897,134	\$ 121,012,293	\$ 123,414,778	\$ 125,865,313	\$ 128,364,858	\$ 130,914,395
			Levelized Revenue	\$89.1665	5																								
																													1
Expenses			0&M	1	35,503,775	5 36,213,850	36,938,127	37,676,890	38,430,428	39,199,036	39,983,017	40,782,677	41,598,331	42,430,297	43,278,903	44,144,481	45,027,371	45,927,919	46,846,477	47,783,406	48,739,075	49,713,856	50,708,133	51,722,296	52,756,742	53,811,877	54,888,114	55,985,876	57,105,59
			Site Leasing	1	254,325	5 259,412	264,600	269,892	275,290	280,796	286,412	292,140	297,983	303,942	310,021	316,221	322,546	328,997	335,577	342,288	349,134	356,117	363,239	370,504	377,914	385,472	393,182	401,045	409,06
			Property Tax	(1.09	6 2,393,395	5 2,441,263	2,490,088	2,539,890	2,590,688	2,642,501	2,695,351	2,749,258	2,804,244	2,860,329	2,917,535	2,975,886	3,035,403	3,096,112	3,158,034	3,221,194	3,285,618	3,351,331	3,418,357	3,486,724	3,556,459	3,627,588	3,700,140	3,774,143	3,849,62
			Insurance	0.3%	6 4,076,549	4,158,080	4,241,242	4,326,067	4,412,588	4,500,840	4,590,856	4,682,674	4,776,327	4,871,854	4,969,291	5,068,677	5,170,050	5,273,451	5,378,920	5,486,498	5,596,228	5,708,153	5,822,316	5,938,762	6,057,538	6,178,688	6,302,262	6,428,307	6,556,874
					42,228,044	43,072,605	43,934,057	44,812,738	45,708,993	46,623,173	47,555,636	48,506,749	49,476,884	50,466,422	51,475,750	52,505,265	53,555,371	54,626,478	55,719,008	56,833,388	57,970,055	59,129,457	60,312,046	61,518,287	62,748,652	64,003,625	65,283,698	66,589,372	67,921,159
																							/						L
																													1
Total Expenses					\$ 42,228,044	\$ 43,072,605	\$ 43,934,057	\$ 44,812,738	\$ 45,708,993	\$ 46,623,173	\$ 47,555,636	\$ 48,506,749	\$ 49,476,884	\$ 50,466,422	\$ 51,475,750	\$ 52,505,265	\$ 53,555,371	\$ 54,626,478	\$ 55,719,008	\$ 56,833,388	\$ 57,970,055	\$ 59,129,457	\$ 60,312,046	\$ 61,518,287	\$ 62,748,652	\$ 64,003,625	\$ 65,283,698	\$ 66,589,372	\$ 67,921,159
Description Direct		04%																											t
Depreciable Plant		91%			20.0%	22.0%	10.2%	11.59	11.59/	E 00/																			t
Depreciation Schedule					20.07	32.0%	227 419 224	142 450 024	142 450 024	71 225 467			-																1
Tax Basis Net Plant				\$ 1 358 849 724	1 111 539 074	715 842 035	478 423 811	335 972 877	193 521 942	122 296 475	122 296 475	122 296 475	122 296 475	122 296 475	122 296 475	122 296 475	122 296 475	122 296 475	122 296 475	122 296 475	122 296 475	122 296 475	122 296 475	-	-	-	-	-	
Tax Dabib Net Fibrit			Average	230 330 404	1,111,555,074	113,042,033	470,423,011	333,812,011	100,021,042	122,230,473	122,230,473	122,230,473	122,230,413	122,230,473	122,230,413	122,230,473	122,230,473	122,230,413	122,230,413	122,230,413	122,200,475	122,230,473	122,200,415						1
Operating Income			Average	200,000,404	(168 274 241)	(314 388 698)	(153 799 975)	(56 611 225	(54 335 783)	19 218 868	92 843 490	95 295 897	97 834 242	100 425 331	103 085 369	105 814 088	108 611 216	111 476 473	114 426 044	117 459 639	120 560 493	123 761 243	127 028 643	130 378 847	58 263 640	59 411 152	60 581 615	61 775 486	62 993 235
Income Taxes					(45 938 868)	(85.828.115)	(41 987 393)	(15 454 864	(14 833 669)	5 246 751	25 346 273	26 015 780	26 708 748	27 416 115	28 142 306	28 887 246	29.650.862	30 433 077	31 238 310	32 066 481	32 913 015	33 786 819	34 678 819	35 593 425	15 905 974	16 219 245	16 538 781	16 864 708	17 197 153
ITC		18%			244 592 950	/ (00,020,110/	(41,001,000)	(10,404,004	(14,000,000)	0,240,701	20,040,210	20,010,100	20,700,740	21,410,110	20,142,000	20,001,240	20,000,002	00,400,011	01,200,010	02,000,401	02,010,010	00,700,010		00,000,420	10,000,014	10,210,240	10,000,101	10,001,100	
PTC					-	-	-	-	-	-	-	-	-	-									· · · · · ·						(
Net Income					\$ 122,257,577	\$ (228,560,583)	\$ (111,812,582)	\$ (41,156,361	\$ (39,502,115)	\$ 13,972,117	\$ 67,497,217	\$ 69,280,117	\$ 71,125,494	\$ 73,009,216	\$ 74,943,063	\$ 76,926,842	\$ 78,960,354	\$ 81,043,396	\$ 83,187,734	\$ 85,393,157	\$ 87,647,479	\$ 89,974,424	\$ 92,349,823	\$ 94,785,422	\$ 42,357,666	\$ 43,191,908	\$ 44,042,834	\$ 44,910,779	\$ 45,796,082
																											1. 1. 1.		[
Plus: Depreciation					247,310,650	395,697,040	237,418,224	142,450,934	142,450,934	71,225,467	-	-	-	-	-	-	-	-	-	-	-	-				-	-	-	· ·
Operating Cash Flow					\$ 369,568,227	\$ 167,136,456	\$ 125,605,642	\$ 101,294,574	\$ 102,948,820	\$ 85,197,584	\$ 67,497,217	\$ 69,280,117	\$ 71,125,494	\$ 73,009,216	\$ 74,943,063	\$ 76,926,842	\$ 78,960,354	\$ 81,043,396	\$ 83,187,734	\$ 85,393,157	\$ 87,647,479	\$ 89,974,424	\$ 92,349,823	\$ 94,785,422	\$ 42,357,666	\$ 43,191,908	\$ 44,042,834	\$ 44,910,779	\$ 45,796,082
																													(
Capital Expenditures				\$ 1,358,849,724	1																								
Free Cash Flows				\$ (1,358,849,724	\$ 369,568,227	\$ 167,136,456	\$ 125,605,642	\$ 101,294,574	\$ 102,948,820	\$ 85,197,584	\$ 67,497,217	\$ 69,280,117	\$ 71,125,494	\$ 73,009,216	\$ 74,943,063	\$ 76,926,842	\$ 78,960,354	\$ 81,043,396	\$ 83,187,734	\$ 85,393,157	\$ 87,647,479	\$ 89,974,424	\$ 92,349,823	\$ 94,785,422	\$ 42,357,666	\$ 43,191,908	\$ 44,042,834	\$ 44,910,779	\$ 45,796,082
																		_											1
Discount Factor		6.36%																											1
		1	NPV 25-years	\$0																									1

				3																								
				2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
Mayflower	Nominal \$	Contract Ye	ear 0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
	Nameplate 8	04																										
	Installed Cost (\$/kW) \$ 3,1)1																										
		Annual Energy Production (MW	'h)	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229	3,310,229
		Net Performance Payment (\$/kW-m	10)	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Revenue	Energy (Annual MWh) 3,310,2	19 Energy Reven	ue																					\$ 208,795,894	\$ 212,971,812	\$217,231,248	\$ 221,575,873	\$ 226,007,391
		PfP Reven	ue	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951	\$ 1,784,951
		Contract Reven	ue	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	\$ 257,403,391	s -	\$ -	\$ -	\$ -	\$ -
	Qualifed Capacity (summer) 213.693	15 Capacity Revenue (summ)	er)	\$ 5,442,549	\$ 5,551,400	\$ 5,662,428	\$ 5,775,677	\$ 5,891,190	\$ 6,009,014	\$ 6,129,194	\$ 6,251,778	\$ 6,376,814	\$ 6,504,350	\$ 6,634,437	\$ 6,767,126	\$ 6,902,468	\$ 7,040,518	\$ 7,181,328	\$ 7,324,955	\$ 7,471,454	\$ 7,620,883	\$ 7,773,300	\$ 7,928,766	\$ 8,087,342	\$ 8,249,089	\$ 8,414,070	\$ 8,582,352	\$ 8,753,999
	Qualifed Capacity (winter) 453.43	59 Capacity Revenue (wint	er)	\$ 23,097,111	\$ 23,559,053	\$ 24,030,234	\$ 24,510,839	\$ 25,001,055	\$ 25,501,076	\$ 26,011,098	\$ 26,531,320	\$ 27,061,946	\$ 27,603,185	\$ 28,155,249	\$ 28,718,354	\$ 29,292,721	\$ 29,878,575	\$ 30,476,147	\$ 31,085,670	\$ 31,707,383	\$ 32,341,531	\$ 32,988,362	\$ 33,648,129	\$ 34,321,091	\$ 35,007,513	\$ 35,707,663	\$ 36,421,817	\$ 37,150,253
		Total Revenue		\$ 287,728,002	\$ 288,298,795	\$ 288,881,004	\$ 289,474,858	\$ 290,080,588	\$ 290,698,433	\$ 291,328,635	\$ 291,971,440	\$ 292,627,102	\$ 293,295,878	\$ 293,978,028	\$ 294,673,822	\$ 295,383,532	\$ 296,107,435	\$ 296,845,817	\$ 297,598,967	\$ 298,367,179	\$ 299,150,756	\$ 299,950,004	\$ 300,765,238	\$ 252,989,278	\$ 258,013,365	\$ 263,137,933	\$ 268,364,993	\$ 273,696,594
		Levelized Reven	ue \$88.3630																									
Expenses		08	kΜ	74,245,636	5 75,730,549	77,245,160	78,790,063	80,365,864	81,973,181	83,612,645	85,284,898	86,990,596	88,730,408	90,505,016	92,315,116	94,161,419	96,044,647	97,965,540	99,924,851	101,923,348	103,961,815	106,041,051	108,161,872	110,325,109	112,531,612	114,782,244	117,077,889	119,419,447
		Site Leasi	ng	531,846	542,483	553,333	564,399	575,687	587,201	598,945	610,924	623,142	635,605	648,317	661,284	674,509	9 688,000	701,760	715,795	730,111	744,713	759,607	774,799	790,295	806,101	822,223	838,668	855,441
		Property T	ax 1.0%	3,714,213	3,788,497	3,864,267	3,941,552	4,020,383	4,100,791	4,182,807	4,266,463	4,351,792	4,438,828	4,527,605	5 4,618,157	4,710,520	4,804,730	4,900,825	4,998,842	5,098,818	5,200,795	5,304,811	5,410,907	5,519,125	5,629,507	5,742,098	5,856,940	5,974,078
		Insuran	ce 0.3%	7,479,613	7,629,205	5 7,781,789	7,937,425	8,096,173	8,258,097	8,423,259	8,591,724	8,763,558	8,938,829	9,117,606	9,299,958	9,485,957	9,675,676	9,869,190	10,066,574	10,267,905	10,473,263	10,682,729	10,896,383	11,114,311	11,336,597	11,563,329	11,794,596	12,030,487
				85,971,307	87,690,734	89,444,548	91,233,439	93,058,108	94,919,270	96,817,656	98,754,009	100,729,089	102,743,671	104,798,544	106,894,515	109,032,405	111,213,053	113,437,314	115,706,061	118,020,182	120,380,585	122,788,197	125,243,961	127,748,840	130,303,817	132,909,894	135,568,091	138,279,453
Total Expenses				\$ 85,971,307	\$ 87,690,734	\$ 89,444,548	\$ 91,233,439	\$ 93,058,108	\$ 94,919,270	\$ 96,817,656	\$ 98,754,009	\$ 100,729,089	\$ 102,743,671	\$ 104,798,544	\$ 106,894,515	\$ 109,032,405	\$ 111,213,053	\$ 113,437,314	\$ 115,706,061	\$ 118,020,182	\$ 120,380,585	\$ 122,788,197	\$ 125,243,961	\$ 127,748,840	\$ 130,303,817	\$ 132,909,894	\$ 135,568,091	\$ 138,279,453
Depreciable Plant	94	%																										
Depreciation Schedule				20.0%	32.0%	19.2%	11.5%	11.5%	5.8%																			
Depreciation				468,722,386	749,955,818	449,973,491	269,984,095	269,984,095	134,992,047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Basis Net Plant			\$ 2,493,204,183	2,024,481,797	1,274,525,978	824,552,487	554,568,393	284,584,298	149,592,251	149,592,251	149,592,251	149,592,251	149,592,251	149,592,251	149,592,251	149,592,251	149,592,251	149,592,251	149,592,251	149,592,251	149,592,251	149,592,251						
-		Avera	ge 371,421,288																									
Operating Income				(266,965,692)	(549,347,757)) (250,537,035)	(71,742,676)	(72,961,615)	60,787,115	194,510,979	193,217,432	191,898,014	190,552,207	189,179,484	187,779,307	186,351,126	184,894,382	183,408,503	181,892,906	180,346,997	178,770,171	177,161,807	175,521,276	125,240,438	127,709,548	130,228,040	132,796,901	135,417,140
Income Laxes		201		(72,881,634)	(149,971,938)) (68,396,611)	(19,585,751)	(19,918,521)	16,594,882	53,101,497	52,748,359	52,388,158	52,020,753	51,645,999	51,263,751	50,873,858	50,476,166	50,070,521	49,656,763	49,234,730	48,804,257	48,365,173	47,917,308	34,190,640	34,864,707	35,552,255	36,253,554	36,968,879
IIC	12	2%		299,184,502																								
PIC				-	-	-	-	-	-	-	-	-	-															
Net Income				\$ 105,100,444	\$ (399,375,819)	\$ (182,140,424)	\$ (52,156,926)	\$ (53,043,094)	\$ 44,192,233	\$ 141,409,482	\$ 140,469,073	\$ 139,509,856	\$ 138,531,455	\$ 137,533,485	\$ 136,515,556	\$ 135,477,269	\$ 134,418,216	\$ 133,337,982	\$ 132,236,143	\$ 131,112,267	\$ 129,965,914	\$ 128,796,634	\$ 127,603,968	\$ 91,049,798	\$ 92,844,841	\$ 94,675,785	\$ 96,543,347	\$ 98,448,261
Diver Deservision				100 700 000	740.055.040	440.070.404	000 004 005	000 004 005	404.000.047																			
Plus: Depreciation				408,722,380	749,955,818	449,973,491	209,984,095	209,964,095	134,992,047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Cash Flow				\$ 5/3,822,830	\$ 350,579,999	\$ 201,833,067	\$ 217,827,169	\$ ∠10,941,001	\$ 179,184,280	\$ 141,409,482	\$ 140,469,073	\$ 139,509,856	\$ 138,531,455	\$ 137,533,485	\$ 130,515,556	\$ 135,477,269	\$ 134,418,216	\$ 133,337,982	\$ 132,236,143	\$ 131,112,267	ə 1∠9,965,914	\$ 128,796,634	\$ 127,603,968	\$ 91,049,798	\$ 92,644,841	ə 94,675,785	a 90,543,347	\$ 98,448,261
Operated Frances alterates			6 0 400 004 400		+	-																						
Capital Expenditures			\$ 2,493,204,183	£ 570.000.000	6 050 570 000	6 007 000 007	6 047 007 400	6 040 044 004	6 470 404 000	6 4 44 400 400	6 4 40 400 070	6 400 500 050	6 400 504 455	* 407 500 405	6 400 545 550	6 405 477 000	C 404 440 040	6 400 007 000	6 400 000 440	6 404 440 007	6 400 005 044	6 400 700 004	6 407 000 000	6 04 040 700	*	6 04 075 705	6 00 540 047	¢ 00.440.004
Free Cash Flows			\$ (2,493,204,183)	\$ 5/3,822,830	\$ 350,579,999	\$ 201,833,067	\$ 217,827,169	\$ ∠10,941,001	\$ 1/9,184,280	\$ 141,409,482	\$ 140,469,073	\$ 139,509,856	\$ 138,531,455	\$ 137,533,485	\$ 130,515,556	\$ 135,477,269	\$ 134,418,216	\$ 133,337,982	\$ 132,236,143	\$ 131,112,267	\$ 129,965,914	\$ 128,796,634	\$ 127,603,968	\$ 91,049,798	\$ 92,644,841	\$ 94,675,785	\$ 90,543,347	\$ 98,448,261
Discount Easter	6.269/																-						<u> </u>					
Discount ractor	0.30%	NDV 25 yes	0.9																									

					2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
Revolution Wind	Nominal \$		Contract Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
	Nameplate	400																											
	Installed Cost (\$/kW)	\$ 4,352																											
			Annual Energy Production (MWh)		1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880	1,646,880
			Net Performance Payment (\$/kW-mo)		0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Revenue	Energy (Annual MWh)	1,646,880	Energy Revenue																						\$101,841,720	\$103,878,554	\$105,956,125	\$108,075,248	\$110,236,753
			PfP Revenue		\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035	\$ 888,035
			Contract Revenue	•	\$ 162,094,164	\$ 162,094,164	\$ 162,094,164	\$ 162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	\$162,094,164	S -	\$ -	\$ -	s -	S -
	Qualifed Capacity (summer)	106.315	 Capacity Revenue (summer) 		\$ 2,654,643	\$ 2,707,736	\$ 2,761,891	\$ 2,817,128	\$ 2,873,471	\$ 2,930,940	\$ 2,989,559	\$ 3,049,350	\$ 3,110,337	\$ 3,172,544	\$ 3,235,995	\$ 3,300,715	\$ 3,366,729	\$ 3,434,064	\$ 3,502,745	\$ 3,572,800	\$ 3,644,256	\$ 3,717,141	\$ 3,791,484	\$ 3,867,314	\$ 3,944,660	\$ 4,023,553	\$ 4,104,024	\$ 4,186,105	\$ 4,269,827
	Qualifed Capacity (winter)	225.59	 Capacity Revenue (winter) 		\$ 11,265,784	\$ 11,491,100	\$ 11,720,922	\$ 11,955,340	\$ 12,194,447	\$ 12,438,336	\$ 12,687,103	\$ 12,940,845	\$ 13,199,662	\$ 13,463,655	\$ 13,732,928	\$ 14,007,587	\$ 14,287,738	\$ 14,573,493	\$ 14,864,963	\$ 15,162,262	\$ 15,465,507	\$ 15,774,818	\$ 16,090,314	\$ 16,412,120	\$ 16,740,363	\$ 17,075,170	\$ 17,416,673	\$ 17,765,007	\$ 18,120,307
			Total Revenue		\$ 176,902,626	\$ 177,181,035	\$ 177,465,012	\$ 177,754,668	\$178,050,117	\$178,351,476	\$178,658,861	\$178,972,394	\$179,292,198	\$179,618,398	\$179,951,122	\$180,290,501	\$180,636,667	\$180,989,756	\$181,349,907	\$181,717,261	\$182,091,963	\$182,474,158	\$182,863,997	\$183,261,633	\$123,414,778	\$125,865,313	\$128,364,858	\$130,914,395	\$133,514,922
			Levelized Revenue	\$108.8306																									
Expenses			O&M	1	36,213,850	36,938,127	37,676,890	38,430,428	39,199,036	6 39,983,017	40,782,677	41,598,331	1 42,430,297	43,278,903	3 44,144,48°	45,027,371	45,927,919	46,846,477	47,783,406	48,739,075	49,713,856	50,708,133	51,722,296	52,756,742	53,811,877	7 54,888,114	55,985,876	57,105,59	4 58,247,706
			Site Leasing		259,412	2 264,600	269,892	2 275,290	280,796	6 286,412	292,140	297,983	3 303,942	310,021	316,221	322,546	328,997	335,577	342,288	349,134	356,117	363,239	370,504	377,914	385,472	2 393,182	401,045	409,06	ð 417,248
			Property Tax	1.0%	3,066,088	3,127,409	3,189,958	3,253,757	3,318,832	2 3,385,208	3,452,913	3,521,971	1 3,592,410	3,664,259	3,737,544	3,812,295	3,888,540	3,966,311	4,045,637	4,126,550	4,209,081	4,293,263	4,379,128	4,466,711	4,556,045	4,647,166	4,740,109	4,834,91	1 4,931,610
			Insurance	0.3%	5,222,313	5,326,759	5,433,294	5,541,960	5,652,799	9 5,765,855	5,881,172	5,998,796	6,118,772	6,241,147	6,365,970	6,493,289	6,623,155	6,755,618	6,890,731	7,028,545	7,169,116	7,312,499	7,458,749	7,607,924	7,760,082	2 7,915,284	8,073,589	8,235,06	1 8,399,762
					44,761,662	45,656,896	46,570,034	47,501,434	48,451,463	49,420,492	50,408,902	51,417,080	52,445,422	53,494,330	54,564,217	55,655,501	56,768,611	57,903,983	59,062,063	60,243,304	61,448,170	62,677,134	63,930,676	65,209,290	66,513,476	67,843,745	69,200,620	70,584,633	71,996,325
Total Expenses					\$ 44,761,662	\$ 45,656,896	\$ 46,570,034	\$ 47,501,434	\$ 48,451,463	\$ 49,420,492	\$ 50,408,902	\$ 51,417,080	\$ 52,445,422	\$ 53,494,330	\$ 54,564,217	\$ 55,655,501	\$ 56,768,611	\$ 57,903,983	\$ 59,062,063	\$ 60,243,304	\$ 61,448,170	\$ 62,677,134	\$ 63,930,676	\$ 65,209,290	\$ 66,513,476	\$ 67,843,745	\$ 69,200,620	\$ 70,584,633	\$ 71,996,325
Depreciable Plant		91%																											
Depreciation Schedule					20.0%	32.0%	19.2%	11.5%	11.5%	6 5.8%																			
Depreciation					316,820,306	506,912,490	304,147,494	182,488,496	182,488,496	91,244,248	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
Tax Basis Net Plant				\$ 1,740,770,913	1,423,950,607	917,038,117	612,890,623	430,402,127	247,913,630	156,669,382	156,669,382	156,669,382	156,669,382	156,669,382	156,669,382	156,669,382	156,669,382	156,669,382	156,669,382	156,669,382	156,669,382	156,669,382	156,669,382						
			Average	306,608,761																									
Operating Income					(184,679,342)	(375,388,351)	(173,252,516)	(52,235,263) (52,889,842	37,686,735	128,249,959	127,555,314	126,846,777	126,124,068	125,386,906	124,635,000	123,868,056	123,085,773	122,287,844	121,473,957	120,643,792	119,797,024	118,933,321	118,052,343	56,901,302	58,021,567	59,164,238	60,329,762	. 61,518,597
Income Taxes					(50,417,460)	(102,481,020)	(47,297,937)	(14,260,227) (14,438,927) 10,288,479	35,012,239	34,822,601	34,629,170	34,431,871	34,230,625	34,025,355	33,815,979	33,602,416	33,384,581	33,162,390	32,935,755	32,704,588	32,468,797	32,228,290	15,534,055	15,839,888	16,151,837	16,470,025	, 16,794,577
ITC		18%)		313,338,764																								
PTC					-	-	-	-	-	-	-	-	-	-															
Net Income					\$ 179,076,883	\$ (272,907,331)	\$ (125,954,579)	\$ (37,975,036	\$ (38,450,915) \$ 27,398,256	\$ 93,237,720	\$ 92,732,713	\$ 92,217,607	\$ 91,692,198	\$ 91,156,280	\$ 90,609,645	\$ 90,052,076	\$ 89,483,357	\$ 88,903,263	\$ 88,311,567	\$ 87,708,037	\$ 87,092,437	\$ 86,464,524	\$ 85,824,053	\$ 41,367,247	\$ 42,181,679	\$ 43,012,401	\$ 43,859,737	\$ 44,724,020
Plus: Depreciation					316,820,306	506,912,490	304,147,494	182,488,496	182,488,496	91,244,248	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Operating Cash Flow					\$ 495,897,189	\$ 234,005,159	\$ 178,192,915	\$ 144,513,460	\$144,037,581	\$118,642,505	\$ 93,237,720	\$ 92,732,713	\$ 92,217,607	\$ 91,692,198	\$ 91,156,280	\$ 90,609,645	\$ 90,052,076	\$ 89,483,357	\$ 88,903,263	\$ 88,311,567	\$ 87,708,037	\$ 87,092,437	\$ 86,464,524	\$ 85,824,053	\$ 41,367,247	\$ 42,181,679	\$ 43,012,401	\$ 43,859,737	\$ 44,724,020
Capital Expenditures				\$ 1,740,770,913																									
Free Cash Flows				\$ (1,740,770,913)	\$ 495,897,189	\$ 234,005,159	\$ 178,192,915	\$ 144,513,460	\$144,037,581	\$118,642,505	\$ 93,237,720	\$ 92,732,713	\$ 92,217,607	\$ 91,692,198	\$ 91,156,280	\$ 90,609,645	\$ 90,052,076	\$ 89,483,357	\$ 88,903,263	\$ 88,311,567	\$ 87,708,037	\$ 87,092,437	\$ 86,464,524	\$ 85,824,053	\$ 41,367,247	\$ 42,181,679	\$ 43,012,401	\$ 43,859,737	\$ 44,724,020
Discount Factor		6.36%																											
			NDV/25-years	02																									

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Attachment N-1d

Joint Testimony of Elizabeth Delaney and Michael Macrae

UNITED STATES OF AMERICA BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.)	Docket No. ER21	000
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JOINT TESTIMONY OF ELIZABETH DELANEY AND MICHAEL MACRAE

1 Q: Please state your name, current employer, title, and business address.

A: *Ms. Delaney*: My name is Elizabeth Delaney, and I work for Borrego Solar Systems, Inc.
(Borrego) as its Director of Wholesale Market Development. My business address is 55
Technology Dr. Suite 102, Lowell, MA 01851.

Dr. Macrae: My name is Michael X. Macrae, and I work for Enel X North America (Enel
X) as its Senior Manager of Regulatory Affairs for the Northeast. My business address is One
Marina Park Drive, Suite 400, Boston, MA 02210.

8 Q: Please describe more fully your current responsibilities.

9 A: *Ms. Delaney*: Since joining Borrego in 2019, I have led Borrego's policy and business 10 development efforts in competitive wholesale markets across the country. In New England, I 11 represent Borrego's interests within New England Power Pool (NEPOOL) and manage efforts to 12 ensure that select assets successfully participate in ISO-NE energy, capacity, and ancillary services 13 markets.

Dr. Macrae: I am currently responsible for the development and execution of Enel X's market advocacy strategy for New England and New York, focusing on protection and growth of existing and new business interests, including but not limited to demand response, distributed energy resources, renewable and storage resources, and electric vehicle infrastructure solutions. I am Enel X's primary NEPOOL member representative, and I represent Enel X's wholesale market

business interests in both the ISO-NE and New York Independent System Operator footprints, as
 well as in state level regulatory proceedings, and at other relevant state policy forums.

3 Q: Please describe your work experience and educational background.

4 A: Ms. Delaney: I have worked in the energy industry for approximately a decade. Prior to 5 joining Borrego, I was the director of energy market policy at Environmental Defense Fund, 6 representing them within NEPOOL, while overseeing engagement in PJM Interconnection LLC 7 (PJM) and Electric Reliability Council of Texas. In November 2018, I was elected by NEPOOL's 8 End User Sector to serve as its Vice-Chair, and I served in this capacity until changing employers 9 in October 2019. I have also worked for Earthwatch Institute, Harvard University, and the Eastern 10 Research Group on a variety of initiatives that advanced energy efficiency, corporate 11 sustainability, and energy policy. I received my undergraduate degree in biology from Boston 12 College and my master's degree in science education from the George Washington University. I 13 also hold a certificate in energy innovation and emerging technologies from Stanford University. 14 In addition, I presented before the Federal Energy Regulatory Commission (the Commission) at 15 the July 15, 2019 Staff-Led Public Meeting on New England fuel security issues (Docket No. 16 EL18-182, et al.). Moreover, I have presented at numerous technical conferences and regularly 17 provide written and oral comments in RTO stakeholder processes and state-level dockets.

Dr. Macrae: I have worked in the air quality and energy industry since 2012. Previous to my work with Enel X, for eight years I managed Harvard University's regulatory air compliance program, permitting combined heat and power units, a new district energy facility, and Title V Operating Permit compliance renewals. I also managed Harvard's wholesale electricity market and competitive retail supplier regulatory affairs, representing Harvard's interests within the NEPOOL stakeholder process. In 2019, while still with Harvard, I served as the elected Vice-Chair of

1 NEPOOL's End User Sector and as a member of the Joint Nominating Committee for the ISO-NE 2 Board of Directors. I am currently the Vice Chair of the NEPOOL Distributed Resources Working 3 Group and the NEPOOL GIS Operating Rules Working Group. I received my undergraduate 4 degree in chemistry and biochemistry from the University of Washington, and my PhD in 5 Chemistry from the University of California San Diego. Moreover, like Ms. Delaney, I presented 6 before the Commission at the July 15, 2019 Public Meeting on regional fuel security challenges 7 and potential improvements. I have also provided written and oral comments in numerous state-8 level proceedings.

9 Q: Ms. Delaney, can you please describe Borrego and that company's interest in this 10 proceeding?

11 Borrego's mission is "to solve the world's energy problems by accelerating the adoption A: 12 of renewable energy." Borrego develops, designs, builds, and maintains distributed and utility 13 scale solar PV and battery storage systems for independent power producers/renewable energy 14 asset owners, utilities, and commercial and public sector customers. To date, Borrego has installed 15 more than 750 megawatts of solar, and our development and construction pipelines include an 16 additional gigawatt of renewable generation capacity. Borrego is the largest private commercial 17 solar company in the U.S. and are rapidly expanding into the utility scale space. Borrego currently 18 employs over 350 professionals nationwide, with headquarters in San Diego, CA and additional 19 offices in Oakland, CA, Lowell, MA, Latham, NY and Chicago, IL. Borrego is developing a large 20 portfolio of solar, storage, and co-located solar plus storage generation assets in New England and 21 is actively seeking market participation for a subset of these resources. This proceeding will impact 22 the ability for these projects to participate in ISO-NE.

1 Q: Dr. Macrae, can you please describe Enel X and its interest in this proceeding?

2 A: Enel North America is the regional organization of the Enel Group, the global energy 3 company, representing Enel Green Power North America, Inc., Enel Trading North America, Inc., 4 and Enel X business lines. Enel Green Power is the global leader in the renewable energy sector 5 with a global managed capacity of over 46 GW across a generation mix that includes wind, solar, 6 geothermal, and hydropower, and is at the forefront of integrating innovative technologies into 7 renewable power plants. In North America, Enel Green Power manages around 6 GW of 8 renewable capacity across 58 plants in 15 US states and one Canadian province. Enel X is a market-9 leading provider of customer-facing clean energy solutions including demand response, energy 10 storage, solar photovoltaic, electric vehicle (EV) charging, and energy intelligence software 11 alongside procurement, billing, and advisory services. Globally, Enel X has deployed 6.3 GW of 12 demand response, 130,000 charging stations, and 110 MW of battery storage. In North America, 13 Enel X has around 4,500 business customers, spanning more than 35,000 sites and representing 14 approximately 4.7 GW of demand response capacity, and over 70 battery storage projects that are 15 operational and under contract. Enel X has deployed around 60,000 EV charging stations in North 16 America. Enel X currently participates in the ISO-NE market with demand response and energy 17 storage and has future plans to participate with both co-located/hybrid and separate solar and 18 storage resources. The outcome of this proceeding will materially impact the participation of such 19 solar and storage in New England's capacity market.

20 **Q:**

In what capacity are you submitting this testimony?

A: *Ms. Delaney*: I am submitting this testimony in the capacity of my role representing
Borrego in policy issues related to U.S. wholesale electricity markets and as Borrego's designated
NEPOOL member representative.

Attachment N-1d – Joint Testimony of Elizabeth Delaney and Michael Macrae

Dr. Macrae: I am submitting this testimony in the capacity of my role representing Enel
 X, overseeing the regulatory affairs engagements with ISO-NE, and as the designated member of
 the NEPOOL Participants Committee for Enel X.

4

Q: What is the purpose of your testimony?

A: In this testimony, we describe our jointly sponsored Tariff changes to the unit-specific offer review process used by the Internal Market Monitor (IMM) to establish FCA offer prices for New Capacity Resources, which we refer to as the "Unit-Specific Offer Review Proposal" in our testimony. We also explain why these NEPOOL-approved changes are enhancements to New England's FCM rules to ensure a consistent, reasonable and justified application of those Rules by the IMM.

Q: Does Borrego or Enel X have any experience with the unit-specific offer review process?

A: *Ms. Delaney*: Yes. In the qualification process for the previous two FCAs (i.e., FCA 14 and 15), Borrego worked in partnership with other companies that sought to submit new capacity resource offers that were below the relevant ORTPs. Specifically, Borrego has direct experience helping its partner entities to navigate through ISO-NE's unit-specific offer review process. Such work has involved preparing documentation and responding to inquiries for new capacity resource offers that have undergone review by the IMM during the FCA qualification process.

Dr. Macrae: Yes. Enel X has direct experience with the unit-specific offer review process,
 having been subject to the IMM's unit-specific offer review during the qualification process for
 resources it sought to enter into both FCAs 14 and 15.

Q: Please describe the unit-specific offer review process and your companies' experience with this process as it relates to these amendments.

3 A: The unit-specific offer review process, administered by the IMM, requires Market 4 Participants to submit data to justify any request to receive a New Resource Offer Floor Price 5 below the default Offer Review Trigger Price (ORTP) for a given technology type. Our direct 6 experiences with the unit-specific offer review process have shown that the IMM has read the 7 Tariff in a way that unreasonably restricts its review and acceptance of bids that are based on the 8 actual economic lives of the resources our respective companies are developing, as many (if not 9 all) have economic lives that are demonstrably greater than twenty years. Moreover, the IMM has 10 indicated that the existing Tariff requires them to use a different weighted average cost of capital 11 (WACC) than the actual WACC for a resource that receives what it views as out-of-market 12 revenues. The problem, however, is that the existing Tariff provides no clear guidance to us as 13 Market Participants or to the IMM on how WACC should be determined for a resource receiving 14 out-of-market revenues. Based on our direct experiences, the IMM has not provided clarity in its 15 application of currently effective Tariff language.

Borrego and Enel also have observed that the unit-specific offer review process has been a significant administrative burden. In Enel and Borrego's case, we work to qualify portfolios of smaller projects, necessitating the creation and collation of multiple cost workbooks, models, and supporting data. Based on our respective experiences, the unit-specific offer review process burdens smaller resources disproportionately as the administrative costs are spread across a greater number of projects representing significantly fewer megawatts than typical, central station power plants.

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Q: Please describe at a high level the Unit-Specific Offer Review Proposal that Borrego and Enel X co-sponsored for NEPOOL consideration.

The jointly sponsored Borrego/Enel X amendment modifies the Tariff by including 3 A: 4 language and a new defined term that would allow a New Capacity Resource to request a resource-5 specific economic life beyond twenty years during the unit-specific offer review process instead 6 of the lifetime used for the default reference unit, provided that the project's sponsor submits 7 sufficient documentation to support the requested economic life. The amendment also provides a 8 non-exhaustive list of the type of documentation that could be offered to support a New Capacity 9 Resource's claimed economic life. Separately, our amendment adds clarification on how a New 10 Capacity Resource that is receiving out-of-market revenue and is seeking a different WACC than 11 the Net CONE reference unit can support an alternative WACC.

12 Q: Please describe the Unit-Specific Offer Review Proposal's revisions concerning the 13 economic life.

A: The amendment clarifies that the IMM has the discretion to accept an economic life that differs from twenty years if the documentation provided is deemed acceptable. Our joint proposal also incorporates the NEPOOL Alternative's new defined term "New Capacity Resource Economic Life." In accordance with this new defined term, there is sufficient evidence that an economic life up to 35 years is within a range of reasonableness reflective of current market investment expectations.¹

20 In Tariff Section III.A.21.2(b), the amendment included the new defined term, as well as 21 proposed new Tariff language that places the burden on a Project Sponsor to provide acceptable

¹ We understand that a further explanation on the purpose of the proposed term "New Capacity Resource Economic Life" is provided by Ms. Abigail Krich's testimony, which is offered in support of the NEPOOL alternative filed in this proceeding.

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1 documentation to justify an economic life beyond twenty years. We also proposed language that 2 would ensure the IMM would consider the documentation provided by the Project Sponsor. 3 Importantly, the Unit-Specific Offer Review Proposal does not suggest that the IMM *must* accept 4 such documentation as proof of an economic life that differs from twenty years. Rather, the intent 5 of NEPOOL's proposed Tariff language is to ensure only that the IMM considers the 6 documentation provided. In our experiences, the IMM used the current Tariff Section III.A.21.2 7 to preclude consideration of a longer economic life than it hypothetical reference unit. In our view, 8 such a narrow interpretation of the Tariff language, is not reasonable or justified.

9 In Tariff Section A.21.2(b)(iv), NEPOOL's proposal includes a list of suggested 10 documents that the IMM may choose to use in its review process to substantiate the New Capacity 11 Resource Economic Life. The revised Tariff language that is included in the NEPOOL Alternative 12 mirrors the PJM tariff language that the Commission recently approved on October 15, 2020 in Docket No. EL16-49-003.² Importantly, the language in the amendment would apply to all 13 14 technology types and would allow for an economic life of up to 35 years, again similar to the 15 language proposed by PJM and approved by the Commission. The proposed language does not 16 limit the type of documents that can be submitted. Rather, the proposed language permits the IMM 17 to consider any supporting information and ultimately accept it if the IMM deems appropriate and 18 supports the proposed New Capacity Resource Economic Life.

19

O: Please describe the Unit-Specific Offer Review Proposal's impact on the WACC.

20 A: Our co-sponsored NEPOOL-supported amendment clarifies that, for New Capacity 21 Resources receiving an out-of-market revenue source that are seeking a different WACC than the 22 Net CONE reference unit, the IMM has the discretion to accept documentation that is submitted

² Calpine Corp. et. al. v. PJM Interconnection, L.L.C., 173 FERC ¶ 61,061 at P 281 (2020).

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1 to demonstrate that the requested WACC is consistent with that of a resource not receiving out-of-2 market revenues. As proposed in NEPOOL's revisions to Tariff Section III.A.21.2(b)(iv), this 3 documentation could include but not be limited to publicly available information sources or private 4 information relevant to projects in North America that are not receiving out-of-market revenues. 5 Again and importantly, the NEPOOL amendment does not require that the IMM must accept such 6 documentation as proof of an alternative WACC, nor does it limit the type of documents that can 7 be submitted. Instead, the NEPOOL-approved Tariff language clarifies that the IMM is permitted 8 to consider this information and ultimately accept it when deemed appropriate. Based on our 9 experiences, the enhanced clarity provided by NEPOOL's Tariff revisions afford entities, like ours, 10 greater certainty in the marketplace.

11 Q: Why does the Borrego and Enel X co-sponsored Unit-Specific Offer Review

12 **Proposal offer appropriate enhancements to the ISO's FCM rules?**

13 A: Our companies have a shared interest in clearing solar PV and battery storage projects in 14 the Forward Capacity Market. Unfortunately, though, based on our respective companies' recent 15 experiences, we have significant concerns that some of the existing FCM rules are outdated and/or 16 do not provide the clarity needed to support adequately the participation of these new technology 17 types, specifically when considered in the broader context of the ISO's ORTP proposal. Relevant 18 to the current unit-specific offer review process, the existing Tariff rules must be clarified both to 19 ensure that new capacity resources like solar and battery know what is expected of them in their 20 FCM offers and to have confidence that their offers will be subject to a fair and transparent unit-21 specific offer review process. More to the point, the applicable Tariff rules should be clear that 22 they permit the IMM to properly capture a resource's full economic life. Changes in the energy 23 industry have disrupted typical market assumptions, including an outdated expectation that a

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generation resource's economic life would not exceed twenty years.³ Increasingly, the financial 1 2 community accepts that the economic life of certain technologies, particularly wind and solar, will 3 often substantially exceed a term of twenty years. Relatively small variations in a resource's 4 economic life can have an outsized impact on its modeled financial performance and, therefore, 5 its resulting New Resource Offer Floor Price. For example, Enel X's internal modeling suggests 6 that increasing the economic life from twenty years to the maximum cap of thirty-five years can 7 impact a unit-specific offer floor price by approximately \$50,000–\$60,000/MW-year. Succinctly 8 stated, incorrect assumptions regarding a resource's economic life can result in unjustifiably high 9 offer floor prices. Such higher prices can, in turn, inflate the capacity prices produced in the 10 auction. As a result, artificially inflated capacity prices could not only deprive certain technologies, 11 which our respective companies are developing, from clearing in a capacity auction and receiving 12 FCM revenues, but also could negatively impact consumers.

Although resource economic lives do not always extend as far as thirty-five years, Project Sponsors rationally expect to be able to make the case to the IMM that they can properly rely on models for their resources that extend economic life beyond twenty years based on their technology and the specifics of their investments. During the most recent FCA 15 qualification process, Enel X and Borrego provided documentation to support an economic life beyond twenty years. Nonetheless, our resources were limited to the twenty-year standardized economic life. Despite the importance of the economic life input, the current ISO-NE Tariff neither specifies how

³ See Wiser et al., Benchmarking Utility-Scale PV Operational Expenses and Project Lifetimes; Results from a Survey of U.S. Solar Industry Professionals, Lawrence Berkeley Nat'l Lab., June 2020, at 3-5, https://eta-publications.lbl.gov/sites/default/files/solar life and opex report.pdf; Wiser et al.. Benchmarking Anticipated Wind Project Lifetimes: Results from a Survey of U.S. Wind Industry Professionals, Lawrence Berkelev Nat'l Lab., 2019, 2–4, https://eta-Sept. at publications.lbl.gov/sites/default/files/wind_useful_life_report.pdf.

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1 the IMM should assess economic life, nor clarifies the documentation a Project Sponsor needs to 2 submit in support of their economic life assumptions. Although we believe the IMM should have 3 discretion in determining a project's economic life, based on our direct experiences with the unit-4 specific offer review process, we are not aware of the IMM using an economic life beyond twenty 5 years. Moreover, the IMM has not indicated during that process (nor in the NEPOOL stakeholder 6 process) whether they have the authority to permit usage of an economic life exceeding the twenty-7 year default. It is desirable and preferable to be able to rely on Tariff language that articulates 8 specific documentation that Project Sponsors may submit to the IMM for consideration. 9 Ultimately, restricting the economic life to twenty years would insulate the unit-specific offer 10 review process from advances in modern technology and innovation, as well as the realities of 11 companies' financing assumptions.

12 PJM's March 18, 2020 filing (Docket No. EL18-178) articulated a similar need: 13 With the expansion of MOPR to apply to all other resource types, 20 years may 14 not, in all instances, be appropriate as different resource types have different 15 inherent characteristics that may allow them to remain economic for a longer period 16 of time. In addition, PJM is clarifying the types of evidence that may be used to 17 justify such an alternate asset life. Further documenting this existing flexibility, 18 when justified by supporting evidence, provides for a reasonable level of flexibility 19 given the diverse demographic of technologies the MOPR now applies to.⁴

⁴ PJM Interconnection, L.L.C., *Compliance Filing Concerning the Minimum Offer Price Rule, Request for Waiver of RPM Auction Deadlines, and Request for an Extended Comment Period of at Least 35 Days*, Docket Nos. EL16-49, EL18-178, ER18-1314, at 74 (Mar. 18, 2020).

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1 On October 15, 2020, the Commission approved PJM's tariff changes to implement this approach. 2 Adopting a similar approach within ISO-NE would benefit both Market Participants and the IMM 3 in providing clarity and guidance as industry standards evolve. 4 Similar to economic life, relatively small variations in a resource's WACC can also have a 5 significant impact on its modeled financial performance and, therefore, its resulting New Resource 6 Offer Floor Price. During the most recent FCA 15 qualification process, Enel X and Borrego 7 observed that the IMM would not allow projects receiving out-of-market revenue to use their 8 actual WACC to justify their offer floor prices. It to us seemed as if the Tariff compelled the IMM 9 to remove any benefit that a project owner may receive from out-of-market revenue, including a 10 lower WACC because of a state contracted out-of-market revenue stream. Our direct experience 11 suggests that a one percent change in WACC changes a resource's New Resource Offer Floor 12 Price by \$11,000/MW-year. Because the project cannot use its actual WACC, there needs to be 13 sufficient guidance on how the IMM will determine the WACC for projects receiving out-of-14 market revenues. NEPOOL's proposal addresses this current deficiency in clarity, for what we 15 believe is to the benefit of both Market Participants and the IMM and ultimately New England 16 consumers as well.

17 Q: How does our co-sponsored (NEPOOL-supported) amendment solve the concerns

18 raised by Borrego and Enel X?

A: Borrego and Enel X believe that these changes resolve confusion around whether an economic life beyond twenty years is permitted in the IMM's unit-specific offer review process and provides a fair and consistent methodology to calculate the WACC for projects receiving outof-market revenue. Clarity on economic life is necessary due to changes in investment and industry trends; indeed, it is expected and accepted that many technologies may have economic lives that

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1 extend well beyond a twenty-year period. Beyond this threshold clarification, we believe that 2 adding detail as to what types of documentation can be used to support an alternative economic 3 life and the associated WACC will improve the efficiency of the review process. Rather than 4 guessing at which documents to submit, Project Sponsors can start by compiling documents 5 suggested by the Tariff, while not constraining themselves to just those documents. This 6 amendment also maintains the ability of the IMM to deem documentation as either acceptable or 7 unacceptable and to reject proposed economic lives that are not credible. The technology-neutral 8 language ensures that all resources, now and in the future, are permitted to submit this information 9 for review.

10 **Q:** Does this conclude your testimony?

11 A: Yes.

I declare, under the penalty of perjury, that the foregoing is true and correct. Executed on April 5, 2021.

Elizabeth Delaney O Director of Wholesale Market Development, Borrego Solar

I declare, under the penalty of perjury, that the foregoing is true and correct. Executed on April 5, 2021.

Michael Macrae Senior Manager Regulatory Affairs, Enel X America

Attachment N-1e

Affidavit of Benjamin W. Griffiths

UNITED STATES OF AMERICA BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.

)

Docket No. ER21-___-000

AFFIDAVIT OF BENJAMIN W. GRIFFITHS ON BEHALF OF THE NEW ENGLAND POWER POOL PARTICIPANTS COMMITTEE

1 My name is Benjamin W. Griffiths. I am an Energy Analyst working for the Massachusetts 2 Attorney General's Office ("AGO") in the Office of the Ratepayer Advocacy. My business address 3 is One Ashburton Place, Boston, MA, 02108. The Massachusetts AGO represents the 4 Commonwealth of Massachusetts, the public interest, and the people of the Commonwealth with 5 respect to electric industry matters that affect consumers in Massachusetts.

My primary responsibility at the AGO is to provide qualitative and quantitative analysis of
proposals by ISO New England ("ISO-NE" or the "ISO") and New England Power Pool
("NEPOOL") stakeholders. I am a voting member at the NEPOOL Transmission and Reliability
Committees and an alternate member at the NEPOOL Markets and Participants Committees.

Prior to joining the AGO in 2018, I was employed by Resource Insight, Inc. where I worked
on resource planning and utility rate design issues. In 2017, I received an M.S. in Energy & Earth
Resources from the University of Texas at Austin. I have authored or co-authored reports,
whitepapers, and a peer-reviewed journal article on various electricity-related topics.

I have worked on technical and policy energy issues since 2012. I previously filed
testimony in FERC Docket No. ER19-1428 on behalf of the AGO on the subject of ISO-NE's
Inventoried Energy Program and in Docket Nos. EL18-182 and ER20-1567 on the subject of ISONE's Energy Security Improvements proposal.

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Attachment N-1e – Affidavit of Benjamin W. Griffiths

1	Over the past five years, I have conducted and written a number of analyses focusing on
2	various aspects of energy storage operation. Public examples include:
3	• My master's thesis on how energy storage affects system emissions under various
4	wholesale market and behind-the-meter dispatch strategies; ¹
5	• An article assessing how different retail rate designs affect storage dispatch and storage
6	induced emissions (relying on co-optimized dispatch strategies); ² and
7	• A whitepaper evaluating the efficacy of a novel storage-focused state policy, relying
8	on an integrated production cost and capacity expansion optimization model, where
9	storage is built and operated to maximize revenues across multiple value streams. ³
0	I am providing this affidavit on behalf of the AGO in support of the NEPOOL-approved
1	amendment that lowers the Energy Storage - Lithium Ion Battery Offer Review Trigger Price
12	("ORTP") from the ISO's proposed ORTP. The NEPOOL-approved proposal relies on a battery
13	dispatch model that I developed, which is described in the memorandum entitled "Revenue for
4	Energy Storage Participating in ISO-NE Energy and Reserves Markets." I am the author of that
15	memorandum, which is attached as Appendix A to this affidavit.

¹ Benjamin W. Griffiths, Finding Carbon Breakeven: Induced Emissions from Economic Operation of Energy Storage in Renewables-Heavy Electricity Systems (June 29, 2017) (unpublished Masters thesis, University of Texas at Austin), <u>https://repositories.lib.utexas.edu/handle/2152/61660</u>.

² Benjamin W. Griffiths, *Reducing emissions from consumer energy storage using retail rate design*, 129 Energy Pol'y 481–90 (2019), <u>https://www.sciencedirect.com/science/article/abs/pii/S0301421519300679</u>.

³ Benjamin W. Griffiths, *Expensive, Ineffective, & Occasionally Counterproductive: Clean Peak Standards Simulation Results for New England*, (Apr. 21, 2020), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3560193.
ER21-___-000 Attachment N-1e – Affidavit of Benjamin W. Griffiths

I declare that the information included in the memorandum is true and correct to the best of my knowledge and belief.

Benjamin W. Griffiths Energy Analyst Massachusetts Attorney General's Office, Office of the Ratepayer Advocacy Executed on April 5, 2021

Appendix A to Attachment N-1e

Revenue for Energy Storage Participating in ISO-NE Energy and Reserves Markets

Alternative ORTP EAS Offset Estimates

Benjamin W. Griffiths | Massachusetts Attorney General's Office | Updated 2021-03-17

1. Introduction

Accurately modeling energy storage dispatch and market revenues poses unique challenges. The revenues that storage generates in wholesale markets depend on its ability to purchase electricity in low-priced periods and sell electricity or reserves in higher priced periods. Storage dispatch is further complicated by its energy-limited status, which introduces significant cross-product and intertemporal opportunity costs, and by technical characteristics such as its efficiency at charging and discharging. Intertemporal opportunity costs reflect the fact that if a battery fully discharges itself in one hour, it cannot discharge itself in the next hour. Cross product opportunity costs reflect the fact that if a battery is used for one product (e.g., selling energy), it may forgo revenues from a second market (e.g., providing reserves).

How storage should operate, conceptually, is generally quite different from how deterministic modeling will simulate how storage could operate. For example, it is easy to describe storage dispatch strategy which will "buy low and sell high" but it is quite difficult to actually implement that strategy in a spreadsheet, to say nothing of the added complexity of thoughtfully accounting for opportunity costs. Deterministic modeling of energy storage will generally leave money on the table that, in practice, a reasonable developer could earn.

As part of the ISO New England ("ISO-NE") Cost of New Entry and Offer Review Trigger Price update process, Concentric Energy Advisors ("CEA") developed estimates of energy storage revenues. After reviewing the deterministic battery model employed by CEA to calculate battery revenues, the Massachusetts Attorney General's Office ("AGO") concluded that battery revenues calculated using optimization techniques would provide more reasonable results than those offered by CEA.¹ In summary, the CEA model discharges for energy based on a predetermined threshold price level (equal to the 95th percentile for annual hourly energy prices), recharges at a fixed time of the day, and sells reserves when neither charging nor discharging. This simplistic model has several obvious shortcomings including:

• Reliance on fixed recharging windows, even if charging in other periods would be cheaper;

¹ See Concentric Energy Advisors, Inc. and Mott MacDonald, *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, Docket No. ER21-787-000, at 88–89 (Dec. 2020) ("CEA Report"); Concentric Energy Advisors, Inc., Battery ORTP dispatch with FRM spreadsheet, https://www.iso-ne.com/static-assets/documents/2020/11/a4 a i battery dispatch ortp version posted nov 24.xlsx (rev. Nov. 24, 2020) ("Battery Dispatch Model").*

- A lack of threshold price differentiation across seasons, even though prices vary over the course of the year;
- The omission of opportunity cost calculations (other than the very high threshold price for selling energy); and
- A failure to incorporate known or knowable pricing information from the day-ahead market, even though the ISO-NE External Market Monitor ("EMM") had previously argued for its inclusion in revenue estimates of this sort.²

To that end, the AGO offers this memorandum outlining a straightforward optimization model to more accurately estimate energy and ancillary services ("EAS") revenues available to a storage device. The model was presented and discussed at three ISO-NE Markets Committee Meetings in the autumn of 2020.³

2. Methodology

The AGO starts from the premise that a storage operator should and would seek to maximize its returns through its participation in available markets. Storage is a relatively new technology and developers are experimenting with different revenue strategies. For its analysis, CEA concluded that energy storage would participate in three ISO-NE markets: energy, ten-minute spinning reserves ("TMSR"), and regulation.⁴

To align with these participation assumptions, the AGO model produces an operational schedule for a storage device which maximizes *expected* revenues from participation in the real-time energy, TMSR, and regulation markets, while respecting the technical limitations of the storage device. As discussed in the Technical Appendix, the model explicitly accounts for cross-product and intertemporal opportunity costs. The AGO makes no judgement about which revenue streams are most valuable and allows the optimization itself determine how best to dispatch the battery.

The AGO ran its optimization model – using CEA-sourced market prices and battery specifications – assuming that storage was *scheduled* optimally based on known day-ahead energy prices, but *operates* only in the real-time market. Put differently, the AGO assumes that storage is dispatched in real-time based on the observed prices from the day-ahead market. Over the three-year study

² *ISO New England Inc.*, Motion to Intervene and Comments of the ISO-New England External Market Monitor, Docket No. ER20-308-000, at 6 (filed Nov. 12, 2019) ("EMM Comments").

³ This memorandum has been updated to reflect material presented at the October and November MC meetings but which was not included in previous versions. Values remain unchanged from the November 2020 update. Material from prior presentations can be found on the ISO-NE website, which can be accessed here: November 2020, <u>https://www.iso-ne.com/static-assets/documents/2020/11/4 b xii ma ago presentation alternative ortp estimates battery stor age.pptx;</u> October 2020, <u>https://www.iso-ne.com/static-assets/documents/2020/10/a5 b ix ma ago presentation.pdf;</u> September 2020, <u>https://www.iso-ne.com/static-assets/documents/2020/09/a6 a ix ma ago presentation alternative storage eas revenue estimates.pdf.</u>

⁴ CEA Report at 88–89.

period used by CEA and the AGO, day-ahead and real-time prices share 81 percent correlation, so high priced hours in the day-ahead market are also generally high-priced hours in real-time. Thus, a battery optimizing its dispatch based on day-ahead energy prices will also tend to perform well in real-time.

Because the AGO model only requires knowledge of known day-ahead energy price curves, the dispatch strategy reflects a readily achievable, albeit simple dispatch scheme. The AGO model **does not** have any foresight of actual real-time prices when developing its dispatch schedule, nor does it update its dispatch strategy in the operating day based on prevailing real-time market conditions.

The AGO's dispatch strategy is based on a dispatch schemes outlined by the ISO-NE External Market Monitor in its comments in ER20-308-000.⁵ The EMM suggested a similar dispatch strategy in which a battery is dispatched in the real-time market according to day-ahead energy prices. In its comments, the EMM noted that the "limited sophistication" of dispatching storage based on day-ahead price curves "represents the minimum that an [energy storage resource] developer could reasonably expect to receive in EAS net revenues."⁶

A full description of the AGO dispatch algorithm, along with data sources and reference to the model itself, is provided in a Technical Appendix at the end of this memorandum.

3. Results

<u>Revenue Estimates</u>

The AGO finds that the CEA revenue estimates for energy storage are unreasonably low assuming that the battery does not participate in the Forward Reserve Market ("FRM") and still somewhat too low assuming that the battery does participate in the FRM. Based on the specific modeling conducted in this analysis, **the AGO proposes alternative real-time energy, TMSR, and regulation revenue estimates of:**

\$ 8,177,487 (\$54.52/kW-year), assuming no FRM participation, and, **\$ 8,812,453 (\$58.75/kW-year)**, assuming participation in the FRM.

In contrast, CEA estimates average EAS revenue from these three markets at \$6,856,653 (\$45.71/kW-year) assuming no FRM participation and \$8,288,982 (\$55.26/kW-year) assuming FRM participation. Given the added revenue available to storage through FRM participation, the AGO concludes that a rational storage operator would participate in the FRM and would thus earn the higher \$ 8,812,453 (\$58.75/kW-year) figure. An energy storage resource dispatched using the AGO's scheme would earn an additional \$523,471 (+6.3%) in revenue compared to the CEA estimate. Table 1 compares AGO and CEA revenue estimates, by product.

⁵ EMM Comments at 6.

		Revenue (Millions, 2025\$)				
Scenario	Model	DA Energy	RT Energy	Reserves	Regulation	Total
No FRM	AGO	Not Estimated	\$1.752	\$2.965	\$3.460	\$8.177
Participation	CEA	\$0.044	\$0.857	\$2.496	\$3.460	\$6.857
With FRM	AGO	Not Estimated	\$1.455	\$3.897	\$3.460	\$8.812
Participation	CEA	\$0.036	\$0.905	\$3.887	\$3.460	\$8.289

Table 1: Estimated Annual Average EAS Revenues from Energy & TMSR, by Case & Source

AGO revenues are higher than CEA for real-time energy and reserve products, and equal to CEA values for regulation by design. The increase in AGO revenues, relative to their CEA alternatives, is primarily due to improved representation of cross-product and intertemporal opportunity costs, and the resulting changes in dispatch.

AGO energy revenues are higher than those offered by CEA because the AGO battery charges and discharges during expected low- and high-priced periods, as defined by the day-ahead price curves. By contrast, the CEA battery discharges whenever prices exceed an annual threshold, even if a higher-priced hour is expected to follow, because it does not rely on day-ahead pricing curves.

AGO reserve revenues are higher because the AGO model reflects cross-product opportunity costs and will try to keep battery full so it can receive a TMSR designation, even if it has previously discharged for energy. By contrast, CEA's battery will not recharge until early morning hours if discharged the previous day, which leaves it unable to provide energy or TMSR for the remainder of the day.

Note, these revenue estimates included in Table 1 only include real-time energy, reserve, and regulation payments. In line with the broader CEA modeling effort, the battery could also earn revenue in the day-ahead energy market (not assessed) and through Pay-for-Performance payments and scarcity rents.⁷ Accordingly, the overall revenues available to storage are even higher than shown.

Dispatch Strategy Improvements

The increased revenue garnered through AGO enhancements to battery dispatch can be readily observed in two examples. The effects are more obvious when the battery is not participating in the FRM, but the same phenomena exist in assuming FRM participation, albeit to a lesser degree. Figure 1 depicts how CEA and AGO dispatch varies over a four-day winter period and Figure 2 depicts how dispatch varies over a two-day spring period. In both, the top frame of the plot depicts AGO dispatch, the middle frame depicts CEA dispatch, the lower frame depicts market prices for energy and TMSR.

⁷ Concentric Energy Advisors, Inc., Revised Discount Cash Flow Model, "Controls & Results" tab, <u>https://www.iso-ne.com/static-assets/documents/2021/03/a03a mc 2021 03 19 dcf model.xlsm</u> (rev. March. 15, 2021) ("DCF Model").



Figure 1: AGO and CEA Dispatch, December 31, 2017 through January 3, 2018

Over this four-day period, the CEA battery is never discharged for energy while the AGO battery cycles about once-per-day. Across these days, the AGO battery earns \$65,000 in energy revenue – \$65,000 more than the CEA battery. Note that even though the market price for TMSR was \$0/MWh throughout this period, the AGO battery quickly recharges after discharge for energy sales so that it is able to provide this product in subsequent hours.



Figure 2: AGO and CEA Dispatch, March 19, 2017 through March 20, 2017

Figure 2 depicts how the CEA battery's lack of intertemporal opportunity costs leaves it empty after discharge for a sustained period. That leaves money on the table. Turning to the CEA dispatch first, we observe that the battery fully discharges on both days. On each of these days, CEA battery sits idle after discharging its energy until the early morning hours when it recharges. By contrast, the AGO model recognizes cross-product and intertemporal opportunity costs, it will dispatch in ways that maximize *expected* revenues between all products. The AGO battery actually earns slightly less energy revenue but nearly doubles overall revenues. On the first day, the AGO battery discharges fully but then quickly recharges. On the second day, it only partially discharges so as to maintain TMSR capability. This strategy reflects the fact that it is expensive to fully discharge for energy, because subsequent reserve revenue is foregone. Over these two days, the AGO battery earns \$35,000 from energy, \$142,000 from TMSR, and \$17,000 from the regulation market, (\$194,000 overall). By contrast, the CEA battery earns \$39,000 from energy sales and \$17,000 from

regulation, but just \$44,000 from TMSR (\$100,000 overall). All said, the AGO dispatch strategy almost doubles battery revenues on this two-day period due to its more parsimonious dispatch.

Revenue Estimate Comparisons

The AGO estimates for energy and reserve revenues (excluding regulation) align with the estimates developed by the EMM in ER20-308 for those two products. The EMM found that storage could earn about \$30/kW between energy and reserves, given knowledge of day-ahead pricing, compared with the AGO estimates of \$35.68/kW and 31.45/kW, with and without the FRM participation. (The EMM also found that a more sophisticated trading strategy based on the day-ahead LMP and CTS transactions could earn \$34/kW-year.⁸)

In contrast, CEA estimates average EAS revenue from energy and TMSR at \$4.79 million per year assuming the FRM participation (\$31.95/kW-year) and at \$3.35 million per year, assuming no FRM participation (\$22.35/kW-year). The former CEA estimate is about 10 percent lower than AGO or EMM values while the latter estimate is about 30 percent lower than the equivalent AGO value and 25 percent lower than the EMM's comparable approach.

The AGO revenue estimate for regulation matches the CEA value, reflecting identical operational strategies for that product. (Both the CEA and AGO values are materially higher than the EMM estimate for regulation, reflecting changes in both strategy and prices.)

Sensitivity of Revenues to Foreknowledge of Real-time Prices

The AGO posits that storage operators could earn significantly more revenue than the AGO calculations, if they relied on more sophisticated dispatch strategies. To assess the potential for additional revenue above the AGO's proposed values, the AGO ran a sensitivity where the storage device has perfect foresight of real-time energy and TMSR prices (as opposed to the day-ahead prices assumed in the proposed values). As expected, perfect foresight enables storage to earn significantly more revenue, as Table 2 demonstrates.

	Revenue (Millions, 2025\$)					
Scenario	DA Energy	RT Energy	Reserves	Regulation	Total	
No FRM	Not Estimated	\$1.752	\$2.965	\$3.460	\$8.177	
With FRM	Not Estimated	\$1.455	\$3.897	\$3.460	\$8.812	
Perfect Dispatch	Not Estimated	\$3.791	\$3.112	\$3.460	\$10.363	

Table 2: Value of Perfect Information in AGO Revenue Estimates.

Overall, if a resource has perfect foresight, it could earn about \$10.4 million per year, 20 to 25 percent more revenue than in the AGO's proposed values. The \$1.5 to \$2 million increase in revenue is due almost entirely to the improved energy dispatch. While it is very unlikely that a

⁸ EMM Comments at 6 ("Approach 3 would have yielded \$34 per kW-year for a resource that does not participate in the regulation market").

battery operator could earn revenues equal to this theoretical maximum, it does suggest that a more sophisticated storage dispatch strategy could potentially yield significantly more revenue than the values proposed by the AGO based on day-ahead price curves.

4. Conclusions

The CEA EAS revenue estimates for battery storage resources are unreasonable, as they do not reflect the actions of a reasonable operator. A reasonable operator using a battery for energy, reserves, and regulation should be able to earn at least \$8,812,453 (\$58.75/kW-year).

The AGO's estimate is conservative: indeed, more advanced dispatch schemes likely will yield higher revenues because there is substantial headroom between what a developer could earn if it had more perfect foresight of real-time prices for energy and reserves, and what it would earn using the AGO's proposed approach.

The AGO's proposed approach corrects the obvious shortcomings of the CEA model that reduce storage revenue. The AGO approach does so by introducing cross-product and inter-temporal opportunity costs, yet does not require that a storage operator has perfect foresight of future market conditions. EAS revenue estimates for ORTPs should not be based on the rosiest of predictions, but neither should they based on the assumption of incompetence. The AGO's dispatch approach sits squarely between these two extremes and reflects the revenue available to a reasonably competent storage operator.

Technical Appendix: Model Formulation & Data Sources

The AGO assessed EAS revenues for an energy storage device using a purpose-built linear optimization model. In an effort to comport with CEA's analysis, the AGO relied on CEA assumptions unless otherwise noted. This section summarizes the model's exogenous price data and battery specification, then outlines the linear program itself.

<u>A1: Pricing Data</u>

The AGO relies on pricing data directly extracted directly from the CEA battery ORTP model in "Battery_ORTPdispatch_2020.09.30wFRM.xlsx" workbook.⁹

- Day-Ahead LMP: "RI RCPF Adj. day-ahead LMP (\$/MWh)" (Column E)
- FRM TMSR Price: "FRM TMSR price (\$/MWh)" (Column H)
- Real-time LMP: "RI RCPF Adj real-time LMP (\$/MWh)" (Column F)
- Real-time TMSR: "RI real-time RCPF Adj TMSR (\$/MWh)" (Column G)
- FRM Hour: "ON or OFF PEAK" (Column D)
- FRM Threshold: "daily threshold price (\$/MWh)" (Column C)

These time series reflect some 26,280 hours of prices, spanning 2017-2019, for Rhode Island (the assumed location of the storage device).

While the battery formulates its dispatch based on day-ahead prices, the optimization model also requires an estimate of opportunity costs for TMSR so that it can explicitly account for trade-offs between products and across time.¹⁰ When formulating its dispatch schedule, the AGO algorithm assumes *expected* TMSR prices of \$5/MWh in all hours. (The battery gets paid the prevailing real-time TMSR market price; the exogenous estimate of TMSR opportunity costs is used for schedule development only).

Regulation revenues were assumed constant at \$21.26/MWh, a value estimated by CEA and ISO-NE. 11

Scenario		Prices used for Battery Operation		Prices used for Revenue	
Information	FRM	Energy TMSR		Energy	TMSR
Day-Ahead	With FRM	DA LMP	\$5/MWh TMSR Estimate	RT LMP	OnPk: FRM OffPk: RT TMSR
	No FRM	DA LMP	\$5/MWh TMSR Estimate	RT LMP	RT TMSR

Table A1: Prices (used for Dispatch	and Revenue by Model Run
--------------------	-------------------	--------------------------

⁹ See note 1 (providing hyperlink to the Battery Dispatch Model).

¹⁰ For example, if possible future TMSR revenues are not factored into dispatch, then the battery may sit empty and idle after discharging, rather than recharging itself. Similarly, if the device assumes TMSR to be zero in future periods, it might elect to earn a pittance in the energy market, rather than maintain its charge to earn TMSR revenue in some later period.

¹¹ CEA Report at 89.

<u> A2: Battery Parameterization</u>

The AGO modeled battery participating in the ISO-NE markets is assumed to have a capacity of 150 MW and can deliver 300 MWh energy at the revenue meter.¹² Details of the battery, and its operational characteristics, are summarized in Table A2.

Parameter	Units	Value	Notes
Capacity	MW-ac	150	Same as CEA, Measured at the Revenue Meter
Stored Energy	MWh-ac	300	Measured at the Revenue Meter
Round-trip Efficiency	%	86%	Same as CEA
One-way Efficiency	%	92%	Assumed Symmetric; $92\% = \sqrt{86\%}$
TMSR Capacity	MW-ac	150	Same as CEA
Regulation Capacity	MW-ac	16.5	Same as CEA
Total Study Withdrawal Limit	GWh-ac	3.285	Same as CEA; = 365 Days x 3 Years x 300 MWh- ac

Table A2: Storage Operational Parameters

A few notes:

- Like CEA, the battery is assumed to have an 86% round-trip efficiency, but unlike CEA the losses on charge and discharge are assumed symmetric (i.e., the battery is ~92% efficient when charging and when discharging). By contrast, CEA assumes that all losses are incurred on discharge.
- The model assumes that the battery can be fully charged and fully discharged in two hours.
- Like CEA, the model limits total dispatch to minimize cell degradation. CEA imposes a firm constraint that limits dispatch to a maximum of one cycle per day, while the AGO model limits dispatch to an *average* of one cycle per day. As discussed below, the AGO also factors into its calculations battery aging caused by cycling for regulation.

A3: Linear Program Formulation

The linear program itself builds on a storage dispatch model previously employed by AGO staff.¹³

¹² *Id.* at 88–89.

¹³ Benjamin W. Griffiths, *Reducing emissions from consumer energy storage using retail rate design*, 129 Energy Pol'y 481–90 (2019), <u>https://www.sciencedirect.com/science/article/abs/pii/S0301421519300679</u>.

The linear program was developed using the standard Python 3.8 scientific stack, Pyomo optimization library¹⁴, and was solved using GLPK.¹⁵

Objective Function (\$)

Objective function of this program seeks to maximize revenues from energy arbitrage, TMSR/FRM, and regulation sales, where **T** is the set of hourly prices, **Q** is the quantity of energy delivered to the meter in each hour, and **P** is the price of each product. Note that for purposes of solving the optimization **P** is the day-ahead price (or *expected* price in the case of TMSR).

$$\max \sum_{t=0}^{T} (Q_{EA,t} \times P_{LMP,t} + Q_{TMSR,t} \times P_{TMSR,t} + Q_{Reg,t} \times P_{Reg,t})$$
(1)

Injection & Withdrawal (measured MW-dc)

Energy may be Injected into, or withdrawn from, the energy storage system ("ESS") at any value between zero and an exogenous charge rate. The battery is assumed to be able to charge and discharge at the same rate, as noted in Eqns 2-4. Separately, total AC **W**ithdrawals from the battery over the course of the study period can be capped using Eqn. 5. This equation accounts for one-way efficiency, η , and has the effect of limiting overall storage cycling. Mirroring the EMM analysis, the AGO factors regulation cycling into its dispatch limits, and assumes that cycling for regulation has $1/10^{\text{th}}$ of the effect on storage aging as cycling for energy arbitrage.¹⁶

$$ESS_{Charge Rate} = ESS_{Discharge Rate}$$
(2)

$$0 \le I_t \le \text{ESS}_{\text{Charge Rate}} \tag{3}$$

$$0 \le W_t \le \text{ESS}_{\text{Discharge Rate}} \tag{4}$$

$$\eta \sum_{t=0}^{T} (W_t) + 0.1 \sum_{t=0}^{T} (Q_{Reg,t}) \le \text{Total Withdrawal Limit}$$
(5)

State of Charge ("SOC") (measured MW-dc)

SOC measures how "full" a battery is at a given point in time. SOC in each period t must equal the SOC at the beginning of the prior period plus injections less withdrawals in that prior period. SOC ranges from zero to the SOC_{max} of about 324 MWh-dc. Note: SOC is measured at the top of each hour.

¹⁴ William E. Hart et al., Pyomo – Optimization Modeling in Python (2nd ed. 2017); William E. Hart et al., *Pyomo: modeling and solving mathematical programs in Python*, 3 Mathematical Programming Computation 219 (2011).

¹⁵ GLPK, *GNU Linear Programming Kit*, <u>https://www.gnu.org/software/glpk/glpk.html</u> (last visited Mar. 13, 2021).

¹⁶ See EMM Comments at 11.

$$0 \le SOC_t \le SOC_{max} \tag{6}$$

$$SOC_t = SOC_{t-1} + I_{t-1} - W_{t-1}$$
⁽⁷⁾

Constraints for Energy Arbitrage

The quantity of energy delivered to, or consumed at, the meter for energy arbitrage equals lossadjusted discharging less loss-adjusted charging. One-way efficiency, η , is assumed symmetric on charging and discharging. Note that injections are negative because they are a cost to the storage owner while withdrawals are positive because they are revenue.

$$Q_{EA,t} = \eta W_t - \frac{I_t}{\eta}$$
(8)

Constraints for TMSR Sales

Selling regulation is almost always more profitable than providing a different service. For simplicity, the battery is set to provide regulation at a fixed 16.5 MW in all periods.

$$Q_{Rea,t} = Q_{Rea\,MAX} = 16.5\,MW\tag{9}$$

Constraints for TMSR Sales

The quantity of energy eligible for TMSR must be less than (a) the loss-adjusted quantity of energy currently stored in the battery, (b) less than the maximum discharge rate (MWh-ac/h); and (c) must not be double-counted with EA sales. The same MW of capacity providing TMSR can, however, also be used to provide regulation. This requires a set of equations,

$$0 \le Q_{TMSR,t} \le Q_{TMSR,MAX} \tag{10}$$

$$Q_{TMSR,t} \ge Q_{Reg,t} + I/\eta \tag{11}$$

$$Q_{TMSR,t} + W\eta \le \eta SOC_t \tag{12}$$

$$Q_{TMSR,t} + W\eta \le Capacity \tag{13}$$

$$Q_{TMSR,t} + I/\eta \le Capacity \tag{14}$$

Constraints for FRM

The FRM, when present, imposes new constraints on how storage is dispatched. In this simple model, a set of time-conditional constraints are added which require TMSR sales to equal 150 MW in each on-peak hour, so long as the LMP for a given on-peak hour is less than the FRM threshold price for that day. The FRM constraint is thus,

If
$$(FRM Hour_t = OnPeak)$$
 and (15)
 $(FRM Threshold_t < P_{DA LMP,t})$ and
 $(FRM Threshold_t < P_{RT LMP,t})$
Then $Q_{EA,t} = 0$

Because the FRM threshold price is relatively high, in almost all on-peak hours $Q_{TMSR,t}$ equals 150 MW and $Q_{EA,t}$ equals zero. To ensure that the FRM resource is paid its full FRM payment during all periods when penalties are not assessed the helper variable $Q_{FRM Supplemental,t}$ is added where,

If
$$(FRM Hour_t = OnPeak)$$
 and (16)
 $(FRM Threshold_t < P_{DA LMP,t})$ and
 $(FRM Threshold_t < P_{RT LMP,t})$
Then $Q_{TMSR,t} + Q_{FRM Supplemental,t} = Q_{TMSR MAX} = 150 MW$

This has the effect of providing additional FRM revenue when the battery is cycling for energy during periods when the LMP exceeds the threshold price. $Q_{FRM Supplemental,t}$ is paid using the same TMSR/FRM prices as the main $Q_{TMSR,t}$ variable.

If the ESS does not participate in the FRM, these constraints are disabled.

A4: Revenue Calculation

Hourly revenue estimates, in nominal dollars, are summed by year, then adjusted into constant 2019\$, then 2025\$, using CEA-sourced scalers. Like CEA, the AGO then takes the simple average of the three years of data to come up with its EAS net revenue estimate for energy storage. This allows for easy integration of the AGO revenue estimates into the overall CEA ORTP estimates.

Note that the revenue output from the model's objective function – used for dispatch scheduling – reflects the quantity of revenue the device would have earned had it taken day-ahead positions and received a flat \$5/MWh for all TMSR sales. This is **not** what the battery actually earned in the real-time market.

Instead, actual revenue earned by the storage device requires additional *post hoc* processing to calculate actual real-time revenues based on the "optimal" dispatch. Recall that the linear program returns how the battery's capacity is split between the three products in each hour. Actual revenues, therefore, equal the hourly position for each product outputted by the model, multiplied by the *real-time* price for each product. These actual revenues – based on real-time prices – could be higher or lower than prices assuming day-ahead positions.

<u> A5: Data</u>

Along with this memorandum, the AGO has released its storage optimization model as well as Excel workbooks with model outputs and revenue calculations.¹⁷ As noted, the optimization model itself is implemented in Python 3.8 and offered as a Jupyter Notebook (filetype: ipynb) for portability.

¹⁷ The AGO alternative EAS model can be accessed here: <u>https://www.iso-ne.com/static-assets/documents/2020/11/a4 b xii ma ago alternative eas model.zip</u>.

Attachment N-1f

Testimony of Sarah Bresolin Silver

UNITED STATES OF AMERICA BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.) Docket No. ER21-__-000

TESTIMONY OF SARAH BRESOLIN SILVER

1 I. INTRODUCTION

2 Q: Please state your name, current employer, title, and business address.

A: My name is Sarah Bresolin Silver. I am Director of Government and Regulatory Affairs
for ENGIE North America Inc. ("ENGIE") for New England. My business address is 9 Channel
Center, 6th Floor, Boston, Massachusetts, 02210.

6 Q: Please describe your work experience and educational background.

7 A: I hold a Bachelor of Arts degree in Political Science from Mount Allison University, a Juris Doctor degree from The University of Western Ontario, and a Master of Law degree from 8 Since June 2019, I have held the position of Director, 9 George Washington University. 10 Government and Regulatory Affairs for ENGIE. In this position, I am responsible for ENGIE's 11 state, regional and federal regulatory and policy activities in New England, including the 12 company's interactions with the ISO New England Inc. ("ISO-NE" or the "ISO") wholesale markets as well as supporting the company's business development efforts in the region. Prior to 13 14 joining ENGIE, I was Assistant Attorney General with the Massachusetts Attorney General's Office from 2016–2019. I currently serve as the Chair of the New England Power Pool 15 ("NEPOOL") Membership Subcommittee. I am also a member of the Board of Directors for the 16 17 Northeast Energy and Commerce Association founded to foster the development and maturation 18 of competitive power markets and which now represents the full range of energy and

environmental interests. Prior to joining the Attorney General's Office, I was counsel with the
 Massachusetts Department of Public Utilities and Assistant Chief Counsel for Environment and
 International Trade at the United States Small Business Administration.

4

Q: Please describe ENGIE and ENGIE's interest in this proceeding.

ENGIE is a subsidiary of ENGIE SA, based in Paris, France. ENGIE SA is one of the 5 A: world's largest independent power producers with over 417 TWh of electricity generation and 6 170,000 employees across 70 countries. Our business plan in North America is to shape a more 7 sustainable future through power generation, retail electricity supply and energy services. 8 9 ENGIE, through its various subsidiaries and affiliates, provides more than three gigawatts of 10 renewable energy for our customers in the US and Canada. ENGIE has over 25 years of experience operating in New England and has participated in the ISO-NE administered markets 11 12 for over a decade. The outcome of this proceeding will have a significant, direct impact on ENGIE's business interest and wholesale market participation as we are developing and 13 operating dozens of co-located and hybrid resources in New England, which we are looking to 14 have participate and clear in the region's Forward Capacity Market ("FCM"). 15

16 Q: In what capacity are you submitting this testimony?

A: I am submitting this testimony in the capacity of my role representing ENGIE in policy issues related to U.S. wholesale electricity markets and as ENGIE's designated member representative of the NEPOOL Participants Committee. I am also submitting this testimony as a proponent of the NEPOOL Alternative and, in particular, as one of the "Joint Sponsors" supporting the Combined Resources ORTP Proposal, described below.

2

1 Q: What is the purpose of your testimony?

In this testimony, I describe certain of the NEPOOL-approved Tariff changes that clarify 2 A: whether and how the weighted average formula in Section III.A.21.2(c) of the ISO-NE Tariff 3 4 applies to certain FCM New Capacity Resources when formulating Offer Review Trigger Prices ("ORTP"). Referred to as the "Combined Resources ORTP Proposal," these Tariff clarifications 5 are a component of the NEPOOL-approved ORTP proposal, which is referred to as the 6 "NEPOOL Alternative." In the NEPOOL stakeholder process that resulted in the NEPOOL 7 Alternative, the Combined Resources ORTP Proposal was jointly sponsored by Advanced 8 9 Energy Economy, Borrego Solar Systems, Inc., Enel X, and ENGIE (collectively the "Joint Sponsors") on behalf of themselves and RENEW Northeast. I also explain why these NEPOOL-10 approved changes provide enhanced clarity in the Tariff and needed certainty in the marketplace 11 for relevant FCM resources, reflecting a preferable approach to the ISO's ORTP proposal. 12

13 **II. BACKGROUND**

14 Q: Please describe the FCM resources affected by the Combined Resources ORTP 15 Proposal.

A: The Combined Resources ORTP Proposal pertains to "hybrid resources" and "co-located resources." Although neither term is defined in the ISO-NE Tariff,¹ the Joint Sponsors understand these terms as follows. A hybrid resource consists of one or more Assets of different technology types behind the same point of interconnection ("POI") that seek to qualify for participation in the FCM as a *single* New Capacity Resource. A co-located resource means two

¹ The Combined Resources ORTP Proposal does not propose to define these terms in the Tariff but uses them as they are commonly understood in New England based on the ISO's description of those resources in publicly accessible materials. *See e.g.*, Post-Technical Conference Comments of ISO New England Inc., Docket No. AD20-9-000, at 1 (filed Sept. 2020). In addition, this proposal does not attempt to redefine the applicability of the weighted average formula on Demand Resources.

or more Assets of different technology types behind the same POI that seek to qualify for
 participation in the FCM separately as *two or more distinct* New Capacity Resources.

To explain further, New England's FCM allows for different market participation models depending on a combined resource's design configuration. In previous comments to the Federal Energy Regulatory Commission ("FERC"), ISO-NE has explained that combined resources may participate in the FCM either as separate capacity resources or as a single capacity resource.² The ISO also stated that it interprets "hybrid" to mean the subset of combined resources that participate as a single capacity resource.³ Figure 1, which was developed by the ISO, aids in understanding the configurations of a co-located resource and a hybrid resource.⁴



Figure 1

² Id.

³ See id. at 2.

⁴ ISO New England Inc., *Market Participation Options for Combined Intermittent/Electric Storage Facilities*, at 12, 15 (Apr. 2020), <u>https://www.iso-ne.com/static-assets/documents/2020/04/20200408-co-located-market-participation.pdf</u>.

ER21- -000

Attachment N-1f – Testimony of Sarah Bresolin Silver

1 **Q:**

What are the benefits offered by hybrid and co-located resources?

2 Hybrid and co-located resources can provide several benefits to New England's electric A: They can assist in further integrating renewable energy resources onto the grid system, 3 grid. 4 enhance reliability, and provide a means to better optimize the use of existing transmission infrastructure, often at a lower cost than other resources (e.g., sharing a POI can reduce 5 6 interconnection costs). They also can realize lower costs in shared real estate, permitting, and project management expenses. In some cases, sharing a POI may enable increased access to tax 7 benefits, such as the Investment Tax Credit. 8

9 Q: Are the Assets that comprise a co-located resource always owned by the same 10 entity?

A: Not necessarily. Although the Assets that comprise a co-located resource may share a POI, they also may be owned and operated by independent entities. Also, these Assets can have separate Asset IDs and may offer, schedule, and settle in the energy market independently of each other. Indeed, it is possible that one Asset participates in the energy and capacity market, while the other only participates in the energy market, such as a battery Asset (participating in the energy market) co-located with a hydro facility (participating in the energy and capacity market).

18 Q: Please describe the current Tariff requirement to use the weighted average
 19 approach when assigning an ORTP for certain FCM resources.

A: Pursuant to a series of ISO-NE filings and FERC Orders in 2014, the requirement to apply the weighted average formula was incorporated into the ISO-NE Tariff and became effective, beginning with FCA 9.⁵ This formula was developed to determine the ORTP for a

⁵ See ISO New England Inc., 147 FERC ¶ 61,109 at P 17 (2014).

1 New Capacity Resource composed of multiple Assets with different technology types. Thus, in its current form, the Tariff requires that combined Assets participating in the FCM as a single 2 New Capacity Resource, i.e., a hybrid resource as shown in Figure 1, has its ORTP calculated in 3 4 accordance with the weighted average formula. Specifically, Tariff Section III.A.21.1.1 5 requires: Where a new resource is composed of assets having different technology types, 6 the resource's Offer Review Trigger Price will be calculated in accordance with 7 the weighted average formula in Section III.A.21.2(c). 8 9 Tariff Section III.A.21.2(c), in turn, provides the weighted average formula. Specifically, that 10 Tariff provision explains that the weighting in the weighted average formula should be done according to the capacity contributed by each asset: 11 For a new capacity resource composed of assets having different technology types 12 the Offer Review Trigger price shall be the weighted average of the Offer Review 13 Trigger Prices of the asset technology types of the assets that comprise the 14 resource, based on the expected capacity contribution from each asset technology 15 16 type.

17 III. NEPOOL'S COMBINED RESOURCES ORTP PROPOSAL

18 Q: Please describe the Combined Resources ORTP Proposal.

A: The NEPOOL-approved Combined Resources ORTP Proposal adds clarifying language to the existing weighted average Tariff provisions. Specifically, without impacting the applicability of the current Tariff, this proposal clarifies Tariff Sections III.A.21.1.1 and III.A.21.2(c). As to the former, the Combined Resources ORTP Proposal makes two clarifying changes. First, it clarifies Tariff Section III.A.21.1.1, as shown in redlines:

1	Where a $\frac{n}{n}$ ew Capacity $\frac{r}{r}$ esource is composed of $\frac{a}{n}$ ssets having different
2	technology types (including, but not limited to, a photovoltaic solar generator
3	sharing a point of interconnection with an energy storage device participating in
4	the energy market as one or more Assets and participating in the capacity market
5	as a single New Capacity Resource), the New Capacity #Resource's Offer Review
6	Trigger Price will be calculated in accordance with the weighted average formula
7	in Section III.A.21.2(c).
8	These proposed changes both clarify that the weighted average approach applies to hybrid
9	resources, such as solar and battery technologies, as well as include Tariff-defined terms rather
10	than using undefined terms to eliminate any perceived ambiguity. Second, the Combined
11	Resources ORTP Proposal also clarifies that the weighted average formula is not used when
12	assigning an ORTP to a co-located resource, as shown in Figure 1. It accomplishes this purpose
13	by adding the following underlined sentence:
14	Where one or more Assets sharing a point of interconnection register as a New
15	Capacity Resource that does not include all of the Assets sharing the point of
16	interconnection, the Offer Review Trigger Price for the New Capacity Resource
17	will be assigned according only to the Asset or Assets contributing to the FCA
18	Qualified Capacity of the New Capacity Resource.
19	This new Tariff language, which also includes Tariff-defined terms, ensures that the
20	ORTP for a co-located resource will be based solely on the Asset(s) contributing to the
21	FCA Qualified Capacity of a particular New Capacity Resource and not by a weighted
22	average that somehow includes Assets that do not contribute anything towards the New

23 Capacity Resource's FCA Qualified Capacity. The "point of interconnection" term refers

to the commonly understood concept (and as illustrated in Figure 1), rather than the Tariff-defined term that applies to FERC-jurisdictional interconnection. The intention is for this to apply to all co-located Assets regardless of whether they interconnect in accordance with the FERC- or state-jurisdictional process.

As to Section III.A.21.2(c), the Combined Resources ORTP Proposal offers the following
changes, as shown in redlines below:

For a **nNew eCapacity** resource composed of **aAssets** having different 7 technology types the Offer Review Trigger price shall be the weighted average of 8 the Offer Review Trigger Prices of the aAsset technology types of the AAssets 9 that comprise the New Capacity #Resource, based on the expected capacity 10 contribution from each aAsset technology type towards the FCA Qualified 11 12 Capacity of the New Capacity Resource. Sufficient documentation must be included in the New Capacity resource's New Capacity Qualification Package 13 or New Demand Capacity Resource Qualification Package to permit the Internal 14

15 Market Monitor to determine the weighted average Offer Review Trigger Price.

These NEPOOL-supported Tariff revisions are also meant to eliminate any perceived ambiguity by replacing undefined terms with Tariff-defined ones. In addition, by deleting "capacity" and adding "FCA Qualified Capacity," this proposal clarifies that in determining the weighting to use in the weighted average formula the Internal Market Monitor (IMM) will use each Asset's contribution towards the FCA Qualified Capacity of the New Capacity Resource when applying the weighted average formula. Taken together, these changes confirm that the weighted average formula applies to hybrid resources and not co-located resources.

- 1 Q: Can you provide an example of how the ORTP for a co-located resource would be
- 2 calculated under the Combined Resources ORTP Proposal's approach?
- 3 A: Yes. Consider the following configuration⁶ and data:



4

Resource	1	Resource 2		
Solar Asse	et 1	Battery Asset 2		
AC nameplate rating	100 MW	Max AC Discharge Rate	50 MW	
Contribution to FCA QC	35 MW	Contribution to FCA QC	50 MW	
ORTP	\$0.000/kW-mo.	ORTP	\$2.601/kW-mo.	

The Combined Resources ORTP Proposal clarifies that Resource 1's ORTP would be \$0.000/kW-month, while Resource 2's ORTP would be \$2.601/kW-month.⁷ This outcome is arrived at because in a co-located configuration, such as this example, there are two separate New Capacity Resources. Only one technology type contributes to the FCA Qualified Capacity of each of the New Capacity Resources. If, on the other hand, the weighted average formula were to apply to this co-located configuration, then both Resource 1 and Resource 2 would be

⁶ See note 4.

⁷ Of note, these ORTPs are proposed in the NEPOOL Alternative.

- 1 assigned an ORTP of \$1.530/kW-month,⁸ resulting in inaccurate ORTPs. Resource 1 would be
- 2 subject to an inaccurately inflated ORTP, and the ORTP for Resource 2 would be unjustifiably
- 3 lower than the ORTP assigned to the underlying Asset technology.
- 4 Q: Can you provide an example of how the ORTP for a hybrid resource would be
- 5 calculated under the Combined Resources ORTP Proposal's approach?
- 6 A: Yes. Consider the following configuration⁹ and data:



7

Resource					
Solar Ass	et	Battery Asset			
AC nameplate rating	100 MW	Max AC Discharge Rate	50 MW		
Contribution to FCA QC	35 MW	Contribution to FCA QC	50 MW		
ORTP	\$0.000/kW-mo.	ORTP	\$2.601/kW-mo.		

8

9

10

If these two Assets were to enter the market as a single New Capacity Resource, as depicted in the above figure, then both would contribute to the FCA Qualified Capacity of that New Capacity Resource. As the current Tariff Section III.A.21.1.1 requires, the weighted

⁸ The weighted average formula for this example is as follows:

$$\frac{(35 \text{ MW} \times \$0.000/\text{kW-mo.}) + (50 \text{ MW} \times \$2.601/\text{kW-mo.})}{(35 \text{ MW} + 50 \text{ MW})} = \$1.530/\text{kW-mo.}$$

⁹ See note 4.

average formula in Section III.A.21.2(c) would apply. In this case, the single New Capacity
 Resource would be assigned an ORTP of \$1.530/kW-month.¹⁰ This is a justifiable and
 reasonable ORTP because both Assets contribute to the New Capacity Resource's FCA
 Qualified Capacity.

5 Q: Why did you co-sponsor the Combined Resources ORTP Proposal?

The Joint Sponsors advocated for this proposal to provide clarity and certainty in the 6 A: market, particularly for new hybrid and co-located resources looking to participate in the FCM. 7 Although the stakeholder process to vet and consider the ISO's ORTP proposal began in May 8 2020 and despite repeated requests for clarification,¹¹ it was not until February 2021 that the 9 IMM offered any concrete explanation as to how it intended to apply the weighted average 10 provision to combined resources.¹² The lack of clarity as to how and when the current Tariff 11 provisions would apply makes it extremely challenging for affected Market Participants, like 12 ENGIE, to make informed, strategic business decisions to participate in the ISO-NE markets. 13 Given the IMM's general recalcitrance during the NEPOOL process to provide guidance as to 14 their plans for implementing these Tariff provisions or any rationale for their planned 15 implementation approach, the Joint Sponsors were compelled to propose amendments that 16 17 resulted in the Combined Resources ORTP Proposal.

¹⁰ The weighted average formula for this example is as follows:

 $\frac{(35 \text{ MW} \times \$0.000/\text{kW-mo.}) + (50 \text{ MW} \times \$2.601/\text{kW-mo.})}{(35 \text{ MW} + 50 \text{ MW})} = \$1.530/\text{kW-mo.}$

¹¹ See RENEW Ne. et al., Amendment to the ORTP Calculation for Combined Resources for FCA 16, at 11 (Feb. 24, 2021), <u>https://www.iso-ne.com/static-assets/documents/2021/02/a02 mc 2021 02 24 joint stakeholder amendment.pptx</u>.

¹² See Memorandum from Internal Market Monitor to NEPOOL Markets Committee, subject: FCA 16 Co-Located Resource Offer Review Trigger Price (Feb. 5, 2021), <u>https://www.iso-ne.com/static-assets/documents/2021/02/a05 mc_2021_02_09_10_imm_memo_co_located_treatment.pdf</u>.

1 Even when the IMM did attempt to offer clarity in writing, it was not sufficiently clear to the Joint Sponsors. For instance, in its March 8, 2021 memorandum, the IMM noted that the 2 entirety of Section III.A.21.2(c) comprised "generic language" that did not "differentiate 3 treatment based on how an asset is registered or owned" and went on to opine that a solar and 4 battery resource are "different" when "combined behind the same point of interconnection as 5 compared to when they are genuinely stand-alone resources."¹³ The IMM was unwilling to 6 provide any assurance as to whether it would apply the weighted average approach if the solar 7 Asset registered as a single FCM New Capacity Resource while the battery Asset did not and, if 8 9 so, how the IMM would determine the weighting. In the end, the Joint Sponsors concluded that 10 NEPOOL's Combined Resources ORTP Proposal was essential to allow entities like ours that are developing and operating co-located and hybrid resources in New England to determine 11 12 whether and how to participate in the wholesale markets, including to qualify, participate, and clear in the FCM. 13

Q: Why do you need the Combined Resources ORTP Proposal to clarify whether and
 how the weighted average formula applies to co-located resources and hybrid resources,
 respectively?

A: The ambiguity promulgated by the IMM does not allow developers of co-located and
hybrid resources to optimize their participation in the competitive wholesale power market.
First, rather than keeping "generic language"¹⁴ that could be misinterpreted or misapplied, the
Combined Resources ORTP Proposal replaces undefined terms with Tariff definitions that the

¹³ Memorandum from Internal Market Monitor to NEPOOL Markets Committee, subject: Co-Located Offer Review Trigger Prices, at 2 (Mar. 8, 2021), <u>https://www.iso-ne.com/static-assets/documents/2021/03/a05_mc_2021_03_09_imm_memo_colocated_ortps.pdf</u>.
¹⁴ Id.

1 Commission has previously approved. The Combined Resources ORTP Proposal clarifies that the term "expected capacity contribution" refers to the expected contribution of each technology 2 type in a hybrid resource towards that hybrid resource's FCA Qualified Capacity. It does not, for 3 4 example, refer to each technology's nameplate rating or some other unidentified factor. The NEPOOL-supported Combined Resources ORTP Proposal provides Market Participants with a 5 clear understanding and expectation of when the weighted average formula would apply (and 6 when it would not) and how it would apply. Without this clarity, as evidenced by the IMM's 7 memorandum and discussions during the NEPOOL stakeholder process, Participants, like 8 9 ENGIE, are unable to make sufficiently informed and reasoned business decisions that are 10 essential to participate in the FCM and to compete fairly against other FCM resources. The Combined Resources ORTP Proposal provides that clarity. 11

Second, regarding co-located resources, there is no reason to impose a different 12 mitigation standard on underlying assets that share a POI than would be applied if those assets 13 had separate POIs. Resources with a common POI can be financed, owned, and operated 14 separately. Also, because the weighting in the weighted average is based on the expected FCA 15 Qualified Capacity contributed by each technology type behind the POI, it does not follow, as 16 the IMM has implied, that one New Capacity Resource contributes to the capacity of an entirely 17 different and separate New Capacity Resource. By providing enhanced specificity and clarity in 18 the Tariff, Market Participants will be able to make informed decisions as to whether and how 19 20 hybrid and co-located resources would be subject to the weighted average formula. In short, the Combined Resources ORTP Proposal represents a just and reasonable approach. 21

Q: Why is it important for Market Participants, such as ENGIE, to know whether and
 how the IMM will apply the weighted average calculation?

A: It is fundamental to administering a transparent and fair FCA qualification process that affected Market Participants know how the IMM intends to apply the weighted average provision. Without this transparency, Market Participants developing co-located and hybrid resources, such as renewable technologies with batteries, face a much greater challenge and bear more risk when deciding whether and how to participate in the FCM and puts them at a disadvantage when compared to their conventional resource type competitors.

9 IV. CONCLUSION

10 Q: Does this conclude your testimony?

11 A: Yes.

I declare, under the penalty of perjury, that the foregoing is true and correct. Executed on April 5, 2021.

Sarah Bresolin Silver Director, Government and Regulatory Affairs

Attachment N-1g

Summary of the NEPOOL Participant Processes Regarding Proposed ORTPs for FCA 16

Summary of the NEPOOL Participant Processes Regarding Proposed ORTPs for FCA 16

This Attachment summarizes the NEPOOL Participant Processes that were employed for New England stakeholders to review, vet and consider both the ISO's ORTP Proposal and the NEPOOL Alternative. As explained below, NEPOOL approved the NEPOOL Alternative by a 72.50% Vote (60% Vote is required for approval). The ISO ORTP Proposal only received 19.04% Vote. The full results from these final votes by the NEPOOL Participants Committee are tabulated in <u>Attachment N-1h</u> included with NEPOOL's filing materials.

I. NEPOOL'S CONSIDERATION OF THE ISO'S METHODOLOGY AND INITIAL SET OF PROPOSED ORTPS

A. Starting in May 2020, the Markets Committee vetted the ISO's first ORTP proposal.

Two months after the pandemic forced NEPOOL, ISO-NE, and State officials to meet via teleconference, the ISO (and its consultants) began presenting its methodology to calculate various Forward Capacity Market (FCM) parameters, including Offer Review Trigger Prices (ORTPs) for implementation beginning with FCA 16.¹ Over the course of numerous meetings in 2020 (most spanning two or three days), NEPOOL Markets Committee members, along with the New England States Committee on Electricity and other State officials, discussed the ISO's modeling assumptions and sought to understand the ISO's decisions as it calculated proposed updates to the ORTP values. Concurrently, regional stakeholders offered their perceptive and insights, identifying corrections and/or adjustments to the ISO's modeling and assumptions. That extended process helped stakeholders better understand the ISO's positions and, in some instances, helped to narrow or resolve disagreements.

B. In November 2020, the NEPOOL Markets Committee recommended a different set of ORTP values.

At its November 2020 meeting, the Markets Committee took a series of votes on the ISO's proposal at that time, including votes on five stakeholder-sponsored amendments to the ORTP-related Tariff revisions of that ISO proposal.² The Markets Committee supported these ORTP-related amendments³ and subsequently recommended, with a 64.04% Vote in favor, that

¹ Specifically, the Markets Committee vetted the Cost of New Entry (CONE) and Net CONE values, the Performance Payment Rate (PPR), a new methodology for calculating the Dynamic De-List Bid Threshold (DDBT), and ORTPs. Because the non-ORTP parameters are the subjects of other filings/proceedings, this summary focuses principally on the relevant facts surrounding the ORTP jump ball filing.

² In addition, the Markets Committee considered but failed to support eight other amendments, all related to the FCM parameters other than the ORTPs. A fulsome explanation of these non-ORTP-related amendments are detailed in NEPOOL's Comments submitted in the pending CONE/Net CONE/PPR proceeding. *See* Comments of the New England Power Pool Participants Committee, Docket No. ER21-787-000, at 6–8 (filed Jan. 21, 2021) (NEPOOL Jan. Comments).

³ Of the five amendments that passed, four were proposed by Union of Concerned Scientists on behalf of RENEW Northeast. The fifth amendment was co-sponsored by Borrego Solar and ENEL X North

the NEPOOL Participants Committee approve an alternative package of FCM parameters that reflected, in addition to the CONE, Net CONE, and PPR values proposed by the ISO, the five amendments to the ORTP provisions of the ISO's then-current proposal.⁴ At the request of the ISO, the Markets Committee also voted the ISO's un-amended proposal, which failed with only a 16.67% Vote in favor.⁵

C. In December 2020, the Participants Committee approved the November 2020 Markets Committee-Recommended Proposal.⁶

At its December 3, 2020 meeting, the Participants Committee first considered a motion to approve the November 2020 Markets Committee-recommended proposal for FCM parameters, including the recommended amendments to the ISO's proposed set of ORTPs. The Participants Committee considered and did not pass a proposed amendment to that Markets Committee recommendation.⁷ It also considered a second amendment that was related to how ORTPs would be determined for combined resources⁸ but that amendment also failed to achieve the requisite voting threshold. Finally, the Participants Committee approved the November 2020 Markets Committee-recommended proposal, with a 71.84% Vote in favor.⁹ This vote outcome reflected some support for the NEPOOL Alternative in all of the six NEPOOL sectors. As it did at the Markets Committee meeting, the ISO also requested that the Participants Committee vote on its un-amended proposal at that time, receiving only an 18.33% Vote in favor.¹⁰

America. *See* Memorandum from NEPOOL Counsel to NEPOOL Participants Committee Members and Alternates, subject: Updated Forward Capacity Market (FCM) Values/Parameters for FCA16, at 2–3 (Nov. 24, 2020), <u>https://nepool.com/uploads/NPC_20201203_Composite6.pdf</u> (describing the five amendments) (pages 147–48 of the PDF). *See also* Memorandum from E. Wasik-Gutierrez, Sec'y, Markets Comm. to NEPOOL Participants Comm., subject: Actions of the Markets Comm. (MC), at 2–8 (Nov. 11 25, 2020), <u>https://www.iso-ne.com/static-assets/documents/2020/11/11_9_thru_10_mc_meeting_actions_final.pdf</u> (showing the vote outcomes for each amendment).

⁴ *Id.* at 8.

⁵ *Id*.

⁶ As explained in New England's response to Order No. 719, the Participants Committee is the Participant body that provides the final input by NEPOOL on changes to the Tariff, Manuals, Operating Procedures and other New England matters. New England's governance arrangements have been established to recognize that some Participants may be unable to participate fully and with the benefit of full management feedback until after the Technical Committees have completed their deliberations and made their recommendations. For that reason, all recommendations from the Technical Committee are considered by the Participants Committee (absent delegation to another representative of NEPOOL). But it is final Participants Committee action that establishes NEPOOL's institutional position. *See* Filing of ISO New England and New England Power Pool in response to Order No. 719, Docket No. ER09-1051 (Apr. 28, 2009).

⁷ This failed amendment was unrelated to the ORTP provisions.

⁸ See Memorandum from Borrego Solar Sys. et al., to Participants Comm. Members and Alternates, subject: Amendment Concerning Offer Review Trigger Price Treatment for Co-Located Assets, at 1 (Revised Dec. 2, 2020), <u>http://nepool.com/uploads/NPC_20201203_Addl_IV_A9.pdf</u>.

⁹ See NEPOOL Jan. Comments at 10.

¹⁰ *See id.* at 11.

Thus, following the December 3 Participants Committee meeting, the ISO was required to submit in a "jump ball" filing both the NEPOOL-approved proposal for FCM parameters and the ISO proposal. The only differences between those two proposals related exclusively to the ORTP values and related Tariff provisions.

II. DEVELOPMENTS AFTER THE DECEMBER 3 NEPOOL VOTE

Following the December 3, 2020 Participants Committee meeting, a number of circumstances changed. First, the New England Power Generators Association (NEPGA) filed a complaint on December 11, 2020, challenging at that time the ISO's proposed Net CONE calculation for FCA 16.¹¹ Soon after, the ISO (in consultation with NEPOOL Counsel) decided to bifurcate its FCM parameter values filing; one filing to propose new CONE/Net CONE/PPR values for FCA 16 and a separate jump ball filing on the ORTPs.¹²

Then, on December 27, 2020, the federal Consolidated Appropriations Act, 2021 (the Act) was signed into law.¹³ Relevant here, the Act extended the beginning of construction deadline for the Production Tax Credit and the Investment Tax Credit (ITC) for certain renewable resources. Because the tax treatment of renewable technology types was a material input into the calculation of ORTPs for such resources, the ISO and its consultants decided to evaluate the impact of the Act, as well as to review with NEPOOL any revisions to previously-considered ORTP provisions ahead of filing the ORTP proposals.

III. NEPOOL CONSIDERATION OF AMENDED ORTP PROPOSALS

A. The Markets Committee recommends changes to the December 3 NEPOOL-Approved ORTP Proposal.

In recalculating ORTPs to incorporate the changes in federal tax law, the ISO proposed several modifications to the proposal that NEPOOL voted in December. Specifically, ISO-NE added two new generating capacity resource ORTP categories (solar¹⁴ and combined solar and battery technology types), proposed revisions to Tariff Sections III.A.21.1.1 and III.A.21.2(c) (stating that the weighted average calculation would only be used when an ORTP for the combination of technology types is not specified in the Tariff), and included new Tariff language to specify the ITC percentages that would be used, *inter alia*, for the solar ORTP adjustments for

¹¹ Complaint and Request for Fast-Track Process of the New England Power Generators Association, Inc., Docket No. EL21-26-000 (filed Dec. 11, 2020).

¹² As noted in its December 31, 2020 transmittal letter in Docket No. ER21-787, the ISO sought a decision on its proposed CONE, Net CONE, and PPR values in time for the FCA 16 qualification process. *ISO New England Inc.*, Updates to CONE, Net CONE, and Capacity Performance Payment Rate, Docket No. ER21-787-000, at 3 (filed Dec. 31, 2020). Concluding that approval of the ORTPs could wait until later in the FCA 16 qualification process, the ISO committed to file the two alternative NEPOOL and ISO ORTP proposals in a subsequent jump ball filing. *Id.* at 41.

¹³ Consolidated Appropriations Act, 2021, Pub. L. No. 116-260, 134 Stat. 1182.

¹⁴ In February 2021, ISO-NE was proposing a new \$0.000/kW-month ORTP value for solar.

Attachment N-1g – Summary of the NEPOOL Participant Processes

FCAs 17 and 18. ISO-NE presented those updated ORTP-related revisions at the February 9–10, 2021 Markets Committee meeting.¹⁵

Two weeks later, on February 24, the Markets Committee met again to vote on the ISO's modified ORTP proposal. In addition, that Committee considered proposals to amend NEPOOL's previously adopted alternative ORTP provisions position in light of the Act and the ISO's proposed modifications.¹⁶ During this same meeting, the Markets Committee also heard from NEPGA's tax consultants, who presented their assessment of the ISO's ORTP model for offshore wind.¹⁷

Ultimately, the Markets Committee supported three changes to NEPOOL's previously approved ORTP provisions,¹⁸ and subsequently voted, by a 71.67% Vote in favor, to recommend that the Participants Committee approve those three changes to the ORTP proposal the Participants Committee had approved in December 2020.¹⁹ In addition, at the request of the ISO, the Markets Committee also considered whether to recommend NEPOOL Participants Committee support for the ISO's revised ORTP proposal. That resolution failed with no Participant voting in support.²⁰

B. The ISO delays final NEPOOL action to make further revisions.

With the February 24 Markets Committee recommendation in hand, the Participants Committee prepared to take final action on the amended ORTP proposals at its regular March 4, 2021 meeting. But, just prior to that meeting, the ISO notified the Participants Committee of further changes to its ORTP proposal and of its desire to withdraw that proposal from consideration by the Participants Committee at its March 4 meeting. First, the ISO indicated that it decided to remove from its proposal new language it claimed was intended to "clarify" how ORTPs would be calculated for co-located resources in FCA 16.²¹ This language had not been

¹⁹ *Id.* at 2.

²⁰ *Id.* at 3.

¹⁵ ISO New England Inc., Offer Review Trigger Prices; Revisions to address new Federal Investment Tax Credit provisions for certain technologies (Feb. 9–10, 2021), <u>https://www.iso-ne.com/static-assets/documents/2021/02/a05_mc_2021_02_09_10_ortps.pptx</u>.

¹⁶ A related impetus behind one of the amendments concerned the ISO and the IMM's newly announced approach for applying the weighted average formula to co-located resources. *See* RENEW Ne. et al., Amendment to the ORTP Calculation for Combined Resources for FCA 16 (Feb. 24, 2021), https://www.iso-ne.com/static-assets/documents/2021/02/a02_mc_2021_02_24_joint_stakeholder_amendment.pptx.

¹⁷ NEPGA's tax consultants challenged the ISO's ORTP discounted cash flow model regarding the application of the ITC. Advantage for Analysts, *Assessment of ORTP Calculations of Offshore Wind Projects* (Feb. 2021), https://www.iso-ne.com/static-assets/documents/2021/02/a02biii mc 2021 02 24 nepga osw ortp.pdf.

¹⁸ Memorandum from J. Dwyer, Acting Sec'y, Markets Comm. to NEPOOL Participants Comm., subject: Actions of the Markets Comm., at 1–2 (Feb. 25, 2021), <u>https://www.iso-ne.com/static-assets/documents/2021/02/a00 mc_2021_02_24_actions.pdf</u>.

²¹ Memorandum from Mark Karl, Vice President Market Development and Settlements, to NEPOOL Participants Comm., subject: ISO Revisions to the Offer Review Trigger Price for Co-Located Resources

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supported by the Markets Committee and was the topic of broadly supported alternative language. Second, the ISO indicated it wished to re-evaluate the treatment of ITCs in its ORTP model in light of NEPGA's challenge to that model at the Markets Committee.²²

Following discussion and clarification of the ISO's intention to assess and modify further its proposal, the Participants Committee chose to defer vote on this matter. The decision came with the understanding that there would be further discussions with the Markets Committee and that a Participants Committee meeting would be scheduled for a vote before the end of March.

C. The Markets Committee recommends further changes to the NEPOOL's previously-approved ORTP proposal.

After the March 4 Participants Committee meeting, the ISO followed through with its plans to revise further its proposal. First, the Internal Market Monitor (the IMM) published a memorandum intended to explain how it planned to apply the weighted average approach for combined resources.²³ Second, in light of its simultaneous proposal to revise its CONE, Net CONE, and PPR values, the ISO proposed small modifications to the ORTPs to conform its calculations to the revised PPR.²⁴

The Markets Committee met on March 19, both to consider and, in the same meeting, vote on any further changes from what had previously been considered by the Markets Committee. At that meeting, the Markets Committee considered and supported further changes to amendments it had already recommended on February 24 for Participants Committee approval.²⁵ Thus, the Markets Committee once again recommended, by 70.02% Vote in favor, Participants Committee approval of a package of ORTP provisions that were different from both the provisions the Participants Committee had approved in December 2020, as well as the ISO's

for FCA 6 (CCP 2025-2026) (Mar. 2, 2021), <u>https://www.iso-ne.com/static-assets/documents/2021/03/npc 20210304 composite5.pdf</u> (page 272 of the PDF).

²³ See Memorandum from Internal Market Monitor, to NEPOOL Markets Comm., subject: Co-Located Offer Review Trigger Prices (Mar. 8, 2021), <u>https://www.iso-ne.com/static-assets/documents/2021/03/a05_mc_2021_03_09_imm_memo_colocated_ortps.pdf.</u>

²⁴ Memorandum from Deborah Cooke, Principal Analyst, to NEPOOL Markets Committee, subject: Updates to the Offer Review Trigger Prices (Mar. 15, 2021), <u>https://www.iso-ne.com/static-assets/documents/2021/03/a03b iso voting memo ortps.docx</u>.

²² Memorandum from ISO New England to NEPOOL Markets Comm., subject: Revisions to the Offer Review Trigger Price for Solar Resources for FCA 16, at 1 (Mar. 10, 2021), <u>https://www.iso-ne.com/staticassets/documents/2021/03/a0_iso_memo_revisions_solar_ortp_fca_16_and_summary_iso_responses_ortp_am_ endments.pdf</u> (explaining that, at the March 4, 2021 Participants Committee meeting, the ISO "was investigating a potential issue in the discounted cash flow . . . model"). In addition, after the March 4 Participants Committee meeting, the ISO informed the Committee that it planned to modify its calculations of CONE, Net CONE, and PPR for FCA 16 in response to Commission questions about those values. *Id.* The PPR value, specifically, has a slight impact to the ORTP calculations.

²⁵ Memorandum from Jay Dwyer, Acting Sec'y, NEPOOL Markets Comm., to NEPOOL Participants Comm., subject: Actions of the MC, at 2–3 (Mar. 19, 2021), <u>https://www.iso-ne.com/static-assets/documents/2021/03/a00_mc_2021_03_19_actions.pdf</u>.
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now twice modified proposal.²⁶ Also, at the ISO's request, the Markets Committee considered whether to recommend NEPOOL Participants Committee support for the ISO's further revised ORTP proposal. It did not, with an 18.76% Vote in favor.²⁷

IV. NEPOOL'S FINAL VOTES ON ALTERNATIVE ORTP PROPOSALS

On March 24, 2021, the Participants Committee considered the Markets Committee's latest recommendation from its meeting five days earlier, as well as the ISO's most recent ORTP proposal. The March 19 Markets Committee recommended changes were considered with no further amendments offered. That final proposal, now referred to as the "NEPOOL Alternative," was approved by the Participants Committee, with a 72.50% Vote in favor.²⁸ At the request of the ISO, the Participants Committee also considered the ISO's modified ORTP proposal, which failed with a 19.04% Vote in favor.²⁹

²⁶ The individual Sector votes at the Markets Committee were as follows: *Generation* – 3.34% in favor, 13.35% opposed, 0 abstentions; *Transmission* – 16.68% in favor, 0% opposed, 0 abstentions; *Supplier* – 4.17% in favor, 12.51% opposed, 6 abstentions; *Publicly Owned Entity* – 16.68% in favor, 0% opposed, 0 abstentions; *Alternative Resources* – 12.38% in favor, 4.13% opposed, 0 abstentions; and *End User* – 16.68% in favor, 0% opposed, 0 abstentions. In addition, the votes from Provisional Members were 0.09% in favor, 0% opposed, and 0 abstentions.

²⁷ The individual Sector votes at the Markets Committee were as follows: *Generation* – 7.16% in favor, 9.54% opposed, 2 abstentions; *Transmission* – 0% in favor, 16.70% opposed, 3 abstentions; *Supplier* – 9.54% in favor, 7.16% opposed, 8 abstentions; *Publicly Owned Entity* – 0% in favor, 16.70% opposed, 0 abstentions; *Alternative Resources* – 2.06% in favor, 14.44% opposed, 0 abstentions; and *End User* – 0% in favor, 16.70% opposed, 0 abstentions.

²⁸ <u>Attachment N1-h</u> at 1.

²⁹ *Id*.

Attachment N-1h

March 24, 2021 NEPOOL Participants Committee Vote Tabulation

MARCH 24, 2020 PARTICIPANTS COMMITTEE MEETING VOTES TAKEN ON ORTP PROPOSALS

TOTAL

Sector	NEPOOL Alternative	ISO-NE Alternative
GENERATION	3.34	7.41
TRANSMISSION	16.68	0.00
SUPPLIER	6.06	9.27
ALTERNATIVE RESOURCES	12.96	2.36
PUBLICLY OWNED ENTITY	16.68	0.00
END USER	16.68	0.00
PROVISIONAL MEMBERS	<u>0.09</u>	<u>0.00</u>
% IN FAVOR	72.50	19.04

GENERATION SECTOR

Participant Name	NEPOOL Alternative	ISO-NE Alternative
CPV Towantic, LLC	0	F
Deepwater Wind Block Island	F	0
Dominion Energy Generation Mktg	0	0
FirstLight Power Management, LLC	0	F
Generation Group Member	F	0
Kleen Energy Systems, LLC	0	A
Marco DM Holdings, LLC	0	0
Nautilus Power, LLC	0	F
NextEra Energy Resources, LLC	0	F
NRG Power Marketing, LLC	0	0
IN FAVOR (F)	2	4
OPPOSED (O)	8	5
TOTAL VOTES	10	9
ABSTENTIONS (A)	0	1

ALTERNATIVE RESOURCES SECTOR

Participant Name	NEPOOL Alternative	ISO-NE Alternative
Renewable Generation Sub-Sector		
ENGIE Energy Marketing NA	F	0
Great River Hydro, LLC	0	F
Jericho Power LLC	0	0
Onward Energy	F	0
Wheelabrator/Macquarie	0	F
Large RG Group Member	F	0
Small RG Group Member	F	0
Distributed Gen. Sub-Sector		
Borrego Solar Systems Inc.	F	0
CLEAResult Consulting, Inc.	F	0
Sunrun Inc.	F	0
Load Response Sub-Sector		
Enel X North America, Inc.	F	0
Maple Energy	F	0
Vermont Energy Investment Corp.	F	0
Small LR Group Member	F	0
IN FAVOR (F)	11	2
OPPOSED	3	12
TOTAL VOTES	14	14
ABSTENTIONS (A)	0	0

TRANSMISSION SECTOR

Participant Name	NEPOOL Alternative	ISO-NE Alternative
Avangrid (CMP/UI)	F	0
Eversource Energy	F	0
National Grid	F	A
IN FAVOR (F)	3	0
OPPOSED	0	2
TOTAL VOTES	3	2
ABSTENTIONS (A)	0	1

SUPPLIER SECTOR

Participant Name	NEPOOL Alternative	ISO-NE Alternative
American PowerNet Management	F	0
BP Energy Company	А	А
Brookfield Renew. Trading & Mktg	0	F
Calpine Energy Services, LP	0	F
Castleton Comm. Merchant Trading	0	F
Cross-Sound Cable Company	А	А
DTE Energy Trading, Inc.	А	А
Clearway Power Marketing LLC	F	0
Dynegy Marketing and Trade, LLC	0	А
Emera Energy Companies	0	А
Exelon Generation Company	А	А
Galt Power, Inc.	А	А
H.Q. Energy Services (U.S.) Inc.	0	F
LIPA	А	A
Marble River, LLC	F	0
Mercuria Energy America, Inc	А	А
PSEG Energy Resources & Trade	0	F
Shell Energy North America (US)	F	0
IN FAVOR (F)	4	5
OPPOSED	7	4
TOTAL VOTES	11	9
ABSTENTIONS (A)	7	9

MARCH 24, 2020 PARTICIPANTS COMMITTEE MEETING VOTES TAKEN ON ORTP PROPOSALS

END USER SECTOR

Participant Name	NEPOOL Alternative	ISO-NE Alternative
Acadia Center	F	0
Associated Industries of Mass.	F	0
Conservation Law Foundation	F	0
Environmental Defense Fund	F	0
Harvard Dedicated Energy Limited	F	0
High Liner Foods (USA) Inc.	F	0
Michael Kuser	А	А
Maine Public Advocate Office	F	0
Mass. Attorney General's Office	F	0
Natural Resources Defense Council	F	0
NH Office of Consumer Advocate	F	0
PowerOptions, Inc.	F	0
The Energy Consortium	F	0
Union of Concerned Scientists	F	0
IN FAVOR (F)	13	0
OPPOSED	0	13
TOTAL VOTES	13	13
ABSTENTIONS (A)	1	1

PUBLICLY OWNED ENTITY SECTOR

Participant Name	NEPOOL Alternative	ISO-NE Alternative
Ashburnham Municipal Light Plant	F	0
Belmont Municipal Light Dept.	F	0
Block Island Utility District	F	0
Boylston Municipal Light Dept.	F	0
Braintree Electric Light Dept.	F	0
Chester Municipal Light Dept.	F	0
Chicopee Municipal Lighting Plant	F	0
Concord Municipal Light Plant	F	0
Conn. Mun. Electric Energy Coop.	F	0
Danvers Electric Division	F	0
Georgetown Municipal Light Dept.	F	0
Groton Electric Light Dept.	F	0
Groveland Electric Light Dept.	F	0
Hingham Municipal Lighting Plant	F	0
Holden Municipal Light Dept.	F	0
Holyoke Gas & Electric Dept.	F	0
Hull Municipal Lighting Plant	F	0
Ipswich Municipal Light Dept.	F	0
Littleton (MA) Electric Light Dept.	F	0
Mansfield Municipal Electric Dept.	F	0
Marblehead Municipal Light Dept.	F	0

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	NEPOOL Alternative	ISO-NE Alternative
Mass. Bay Transportation Authority	F	0
Mass. Mun. Wholesale Electric Co.	F	0
Merrimac Municipal Light Dept.	F	0
Middleborough Gas and Elec. Dept.	F	0
Middleton Municipal Electric Dept.	F	0
New Hampshire Electric Cooperative	F	0
Norwood Municipal Light Dept.	F	0
Pascoag Utility District	F	0
Paxton Municipal Light Dept.	F	0
Peabody Municipal Light Plant	F	0
Princeton Municipal Light Dept.	F	0
Reading Municipal Light Dept.	F	0
Rowley Municipal Lighting Plant	F	0
Russell Municipal Light Dept.	F	0
Shrewsbury's Elec. & Cable Ops.	F	0
South Hadley Electric Light Dept.	F	0
Sterling Municipal Electric Light Dept.	F	0
Stowe (VT) Electric Dept.	F	0
Taunton Municipal Lighting Plant	F	0
Templeton Municipal Lighting Plant	F	0
Village of Hyde Park (VT) Elec. Dept.	F	0
VT Public Power Supply Authority	F	0
VT Public Power Supply Authority	F	0
Wakefield Mun. Gas and Light Dept.	F	0
Wallingford, Town of	F	0
Wellesley Municipal Light Plant	F	0
West Boylston Mun. Lighting Plant	F	0
Westfield Gas & Electric Light Dept.	F	0
	49	0
	0	49
	49	49
ABSTENTIONS (A)	0	0

PROVISIONAL MEMBERS

Participant Name	NEPOOL Alternative	ISO-NE Alternative
Anbaric Development Partners, LLC	F	F
IN FAVOR (F)	1	1
OPPOSED	0	0
TOTAL VOTES	1	1
ABSTENTIONS (A)	0	0

Attachment N-1i

NEPOOL Marked Tariff

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 (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); (6) with respect to Demand Bids may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Demand Bids may contain multiple sets of quantity and price pairs for each hour); (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 each hour); and (7)

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 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, backto-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 or Non-Market Participant 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 Resource Economic Life is the number of years that is the lesser of (a) the period of time that a New Capacity Resource of a given technology type or types would reasonably be expected to

operate before the resource becomes unprofitable for at least two consecutive years, (b) the expected physical operating life of the resource, or (c) 35 years.

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.

<u>Offer Review Trigger Prices</u> are the prices specified in Section III.A.21.1 of Market Rule 1 associated with the submission of New Capacity Offers in the Forward Capacity Auction.

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 operation of the rights and responsibilities for the administration for the rights and responsibilities for the administration 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(1) 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 nondesignated 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 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 enduse 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 Sence of that action the Sence of that action 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 Sence of that action the Sence of that action 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 systemwide 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
 - 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/kWmonth;
 - (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
 - 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/kWmonth;
 - (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
 - 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/kWmonth

(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 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 $(1 \le m \le 5)$ submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, ..., p_m$, where $P_S > p_1 > p_2 > ... > p_m \ge P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, ..., q_m$. 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:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2$$

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-H_ist 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)(ii). 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 Commissionapproved 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 Commissionapproved 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 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)(ii). 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 another bid for the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

Repowering. Offers and bids associated with a resource participating in the Forward Capacity (e) 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:

- 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 importconstrained 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:

- 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 exportconstrained 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 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 importconstrained 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]. Referencesin this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward CapacityAuction Starting Price for the Forward Capacity Auction associated with the relevant CapacityCommitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is \$11.35/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is \$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) (except that the bonus tax depreciation adjustment described in Section

III.A.21.1.2(e)(5) shall not apply). 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 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 Capacity Commitment Periods, as elected pursuant to 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, 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. 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 Commissionapproved 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 Commissionapproved 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 reliability 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.13.1.2.1.2.

(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.13.1.2.2.3 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 Clearing Price in the Rest-of-Pool 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), 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
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 Obligations (total acquired less total shed) in the substitution 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 exportconstrained 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 Restof-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.13.1.1.2 (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.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this *Appendix A*.

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this *Appendix A* shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this *Appendix A*. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this *Appendix A*.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor and External Market Monitor for and External Market Monitor is created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this *Appendix A*, the provisions of *Appendix A* shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III. A.17.3 are also part of the Participants Agreement and cannot be modified in either *Appendix A* or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this *Appendix A* are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this *Appendix A*). In the event the Internal Market Monitor or External Market Monitor of its

identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

- (b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.
- (c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the External Market Monitor shall perform the following functions:

- (a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this *Appendix A*, in accordance with the provisions of Section III.A.17 of this *Appendix A*.

- (c) Conduct evaluations and prepare reports on its own initiative or at the request of others.
- (d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this *Appendix A*.
- (f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.
- (g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this *Appendix A*, as appropriate.
- (h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the Internal Market Monitor shall perform the following functions:

- (a) Maintain *Appendix A* and consider whether *Appendix A* requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.
- (b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this *Appendix A*.
- (c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this *Appendix A*.
- (d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this *Appendix A*.
- (e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.
- (g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this *Appendix A*.
- (h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

- (i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this *Appendix A*.
- (j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this *Appendix A* are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:
 - (i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.
 - (ii) Uneconomic production from a Resource, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.
 - (iii) Anti-competitive Increment Offers and Decrement Bids, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this Appendix A.
 - (iv) Anti-competitive Demand Bids, which are addressed in Section III.A.10 of this AppendixA.
 - Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend *Appendix A* as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of

the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

- (k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:
 - (i) Anti-competitive gaming of Resources;
 - (ii) Conduct and market outcomes that are inconsistent with competitive markets;
 - (iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;
 - (iv) Actions in one market that affect price in another market;
 - (v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this *Appendix A*, interfere with efficient market operation, both short-run and long-run; and
 - (vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this *Appendix A*. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this *Appendix A*. If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

- (1) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.
- (m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with *Appendix B* of this Market Rule 1.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this *Appendix A* for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule 1 (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this *Appendix A*. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this *Appendix A*, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under *Appendix B* of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

- (a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:
- (b) Notwithstanding the foregoing or any other provision of this *Appendix A*, and as more fully described in Section III.B.3.2.6 of *Appendix B* to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this *Appendix A*, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this *Appendix A* or in *Appendix B* to this Market Rule 1.

III.A.3.Consultation Prior to Determination of Reference Levels for Physical and Financial
Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant. In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this Appendix A, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this *Appendix A* for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resourcespecific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer

or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus \$2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of	Months Precluded (starting
Incidents	from most-recent incident)
1	2

2 or more	6
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III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

- (a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
- (b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,
- (c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
- (d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

- (a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
- (b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

- (a) all Supply Offer parameters shall be reviewed for economic withholding;
- (b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;
- (c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

- (a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;
- (b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

- (a) for purposes of the Real-Time Energy Market, the Resource is located on the importconstrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;
- (b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than \$25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

- (a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
- (b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or \$100/MWh, whichever is lower. Offer block prices below \$25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or \$100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or \$25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or \$25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

- i. local first contingency;
- ii. local second contingency;
- iii. VAR or voltage;
- iv. distribution (Special Constraint Resource Service);
- v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

- (a) If the Resource is starting from an offline state, the Start-Up Fee;
- (b) The sum of the No Load Fees for the Commitment Period; and
- (c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 "General Threshold Energy Mitigation" or III.A.5.5.2 "Constrained Area Energy Mitigation" is in effect for the following duration:

- (a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:
 - i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,
 - ii. for constrained area energy mitigation, the Resource is not located within a constrained area.
- (b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 "Constrained Area Energy Mitigation"), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 "Manual Dispatch Energy Mitigation" is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource's Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 "General Threshold Commitment Mitigation", III.A.5.5.5 "Constrained Area Commitment Mitigation", or III.A.5.5.6 "Reliability Commitment Mitigation" is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 "Start-Up Fee and No-Load Fee Mitigation" is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as

part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a startup state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

Market Participants are responsible for providing the Internal Market Monitor with all the information and data necessary for the Internal Market Monitor to calculate up-to-date Reference Levels for each of a Market Participant's Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

- (a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.
- (b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.
- (c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, Interruption Costs and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of an offer according to the following hierarchy, under which the first method that can be calculated is used:

- (a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
- (b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
- (c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

- (a) When in any hour the cost-based Reference Level is higher than either the accepted offerbased or LMP-based Reference Level.
- (b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
- (c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
- (d) For any Operating Day for which, during the previous 90 days:
 - the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
 - (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
- (e) When in any hour the incremental energy parameter of an offer, including adjusted offers pursuant to Section III.2.4, is greater than \$1,000/MWh.

For the purposes of this subsection:

- A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.
- ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.
- iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.
- iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.
- (e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.
- (f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:
 - (i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,
 - (ii) No-Load Fee or its corresponding fuel blends,
 - (iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,
 - (iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and
 - (v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

- (a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".
- (b) Costs must be documented.
- (c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible. All cost estimates, including opportunity cost estimates, must be quantified and analytically supported.
- (d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.
- (e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:
- Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and
- ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy/Reduction:

(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

- (a) emissions limits;
- (b) water storage limits;
- (c) other operating permits that limit production of energy; and
- (d) reducing electricity consumption.

No-Load:

(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel,
emissions or variable and maintenance costs.

Start-Up/Interruption:

(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. [Reserved.]

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor the Energy Market as outlined below:

- (a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.
- (b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: (LMP real time / LMP day ahead) – 1. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.
- (c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between

the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as: $(LMP_{real time} / LMP_{day ahead}) - 1.$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

- (i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.
- Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.
- (iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations is greater than the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the

number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

- (a) [Reserved].
- (b) Section III.13.1.2.3.1.6.3 Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.
- (c) Section III.13.1.2.3.2 Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.
- (d) Section III.13.1.3.3A(d) Review by Internal Market Monitor of offers from Existing Import Capacity Resources.
- (e) Section III.13.1.3.5.6 Review by Internal Market Monitor of Offers from New Import Capacity Resources.
- (f) Section III.13.1.7 Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this *Appendix A*. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer *Appendix B* in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement. Article 5 of the form of Cost-of-Service Agreement in *Appendix I* to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Market Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Cost Recovery Request Following Capping.

If as a result of an offer being capped under Section III.1.9, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was capped, the Market Participant may, within 20 days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit an additional cost recovery request to the Internal Market Monitor.

A request under this Section III.A.15 may seek recovery of additional costs incurred for the duration of the period of time for which the Resource was operated at the cap.

III.A.15.1.1. Timing and Contents of Request.

Within 20 days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant requesting additional cost recovery under this Section III.A.15.1 shall submit to the Internal Market Monitor a request in writing detailing: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data, documentation and calculations for those costs; and (ii) an explanation of why the actual costs of operating the Resource exceeded the capped costs.

III.A.15.1.2. Review by Internal Market Monitor.

To evaluate a Market Participant's request, the Internal Market Monitor shall use the data, calculations and explanations provided by the Market Participant to verify the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, using the same standards and methodologies the Internal Market Monitor uses to evaluate requests to update Reference Levels under Section III.A.3 of Appendix A. To the extent the Market Participant's request warrants additional cost recovery, the Internal Market Monitor shall reflect that adjustment in the Resource's Reference Levels for the period covered by the request. The ISO shall then re-apply the cost verification and capping formulas in Section III.1.9 using the updated Reference Levels to re-calculate the adjustments to the Market Participant's offers required thereunder, and then shall calculate additional cost recovery using the adjusted offer values.

Within 20 days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the Market Participant's request, detailing (i) the extent to which it agrees with the request with supporting explanation, and (ii) a calculation of the additional cost recovery. Changes to

credits and charges resulting from an additional cost recovery request shall be included in the Data Reconciliation Process.

III.A.15.1.3. Cost Allocation.

The ISO shall allocate charges to Market Participants for payment of any additional cost recovery granted under this Section III.A.15.1 in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.15.2. Section 205 Filing Right.

If either

(a) as a result of mitigation applied to a Resource under this *Appendix A* for all or part of one or more Operating Days, or

(b) in the absence of mitigation, as a result of a request under Section III.A.15.1 being denied in whole or in part,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was mitigated or the Section III.A.15.1 request was denied, the Market Participant may submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. For filings to address cost recovery under Section III.A.15.2(a), the filing must be made within sixty days of receipt of the first Invoice issued containing credits or charges for the applicable Operating Day. For filings to address cost recovery under Section III.A.15.2(b), the filing must be made within sixty days of receipt of the first Invoice issued that reflects the denied request for additional cost recovery under Section III.A.15.1.

A request under this Section III.A.15.2 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having a Section III.A.15.1 request denied, costs incurred for the duration of the period of time addressed in the Section III.A.15.1 request.

III.A.15.2.1. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data

and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource, as reflected in the original offer and to the extent not recovered under Section III.A.15.1, exceeded the costs as reflected in the capped offer; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.2.2. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the applicable Invoice, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15.2 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2.1 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15.2 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.2.

III.A.15.2.3. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in *Appendix D* to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

• Imposition of a mitigation remedy.

• Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this *Appendix A*, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

- (a) the opportunity costs associated with Demand Reduction Offers;
- (b) the accuracy of Demand Response Baselines;
- (c) the method used to achieve a demand reduction, and;
- (d) the accuracy of metered demand reported to the ISO.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this Appendix A and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this Appendix A.

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this *Appendix A*.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of *Appendix A*. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

- Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.
- (ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.
- (iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.
- (iv) Review and assessment of the effectiveness of *Appendix A* and the administration of *Appendix A* by the Internal Market Monitor for consistency and compliance with the terms of *Appendix A*.
- Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

- (a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;
- (b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;
- (c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,
- (d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). With respect to state regulatory bodies and state attorneys general ("authorized state agencies"), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government

agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as *Exhibit 5*.

III.A.18.2. Additional Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of *Appendix A*, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

- (B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information
 - The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);
 - (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
 - (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
 - (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
 - (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;
 - (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
 - (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

- (A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.
- (B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information.
 - (1) A detailed narrative describing the perceived market design flaw(s);
 - (2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;
 - (3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;
 - (4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the twelfth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 202<u>5</u>1) shall be as follows:

Generating Capacity Resources	
Technology Type	Offer Review Trigger Price (\$/kW-month)
Simple Cycle eCombustion &Turbine	\$ <u>5.355</u> 6.503
eCombined eCycle gGas tTurbine	\$ <u>9.811</u> 7.856
<u>⊖O</u> n- <u>sS</u> hore <u>₩</u> Wind	\$ <u>0.000</u> 11.025
Off-Shore Wind	<u>\$0.000</u>
<u>Energy Storage Device – Lithium Ion</u> <u>Battery</u>	<u>\$2.601</u>
Photovoltaic Solar	<u>\$0.000</u>

Demand Capacity Resources - Commercial and Industrial		
Technology Type	Offer Review Trigger Price (\$/kW-month)	
Load Management (Commercial / Industrial)and/or previously installed Distributed Generation	\$ <u>0.750</u> 1.008	
Previously Installed Distributed Generation	<u>\$0.750</u>	
nNew Distributed Generation	<u>b</u> Based on generation technology type	

On-Peak Solar	<u>\$5.414</u>
Energy Efficiency	\$0.000

Demand Capacity Resources — Residential	
Technology Type	Offer Review Trigger Price (\$/kW-month)
Load Management	\$7.559
previously installed Distributed Generation	\$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	\$0.000

Other Resources	
All other technology types	Forward Capacity Auction Starting Price

Where one or more Assets sharing a point of interconnection register as a New Capacity Resource that does not include all of the Assets sharing the point of interconnection, the Offer Review Trigger Price for the New Capacity Resource will be assigned according only to the Asset or Assets contributing to the FCA Qualified Capacity of the New Capacity Resource.

Where a **n**<u>N</u>ew <u>Capacity</u> **F**<u>R</u>esource is composed of **a**<u>A</u>ssets having different technology types (including, but not limited to, a photovoltaic solar generator sharing a point of interconnection with an energy storage device participating in the energy market as one or more Assets and participating in the capacity market as a single New Capacity Resource), the New Capacity **F**<u>R</u>esource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period. For 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, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. 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.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties), over the New Capacity Resource Economic Life of the project.

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency

programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1)——For the simple cycle combustion turbine and combined cycle gas turbine technology types, Eeach line item associated with capital costs that is included in the capital budgeting model will be <u>updated to</u> reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114). For all other Generating Capacity Resource technology types, each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the levelized cost of energy for that technology as published by Bloomberg.associated with the indices included in the table below:

Cost Component	Index
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"
steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS "Quarterly Census of Employment and Wages" 2371 Utility
	System Construction Average Annual Pay:
	 Combustion turbine and combined cycle gas turbine costs
	to be indexed to values corresponding to the location of
	Hampden County, Massachusetts

	 On shore wind costs to be indexed to values corresponding
	to the location of Cumberland County, Maine
other labor	BLS "Quarterly Census of Employment and Wages" 2211 Power
	Generation and Supply Average Annual Pay:
	 Combustion turbine and combined cycle gas turbine costs
	to be indexed to values corresponding to the location of
	Hampden County, Massachusetts
	 On-shore wind costs to be indexed to values corresponding
	to the location of Cumberland County, Maine
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate
	consumers for the account of others (transportation only)"
fuel inventories	Federal Reserve Bank of St. Louis "Gross Domestic Product:
	Implicit Price Deflator (GDPDEF)"

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	Index
labor, administrative and	BLS "Quarterly Census of Employment and Wages" 2211 Power
general	Generation and Supply Average Annual Pay:
	 Combustion turbine and combined cycle gas turbine costs
	to be indexed to values corresponding to the location of
	Hampden County, Massachusetts
	- On-shore wind costs to be indexed to values corresponding
	to the location of Cumberland County, Maine
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis "Gross Domestic Product:
	Implicit Price Deflator (GDPDEF)"

(32) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 above will be adjusted by the relevant multiplier.

(4<u>3</u>) The energy and ancillary services offset values for <u>gas each</u> technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the <u>most recent</u> Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub

<u>Day-Ahead Peak On Peak electricity prices, as published by ICE for the first five trading days in</u> <u>February, for each the months in the Capacity Commitment Period beginning June 1 of the Capacity</u> <u>Commitment Period to which the updated value will apply, 2021, as published by ICE</u>.

The energy and ancillary services offset values for non-gas technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE for the first five trading days in February, for each month of the Capacity Commitment Period to which the updated value will apply.

(54) Renewable energy credit values in the capital budgeting model shall be updated based on the <u>first</u> most recent MA Class 1 REC prices <u>published in February</u> for the <u>five</u> vintages closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(5) The bonus tax depreciation adjustment included in the financial model for the Offer Review Trigger Prices (which is 40 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 20 percent for the Capacity Commitment Period beginning on June 1, 2026, and zero for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(6) The Investment Tax Credit input into the capital budgeting model for the Photovoltaic Solar Generating Capacity Resource shall be 26 percent for the Capacity Commitment Period beginning on June 1, 2026, 22 percent for the Capacity Commitment Period beginning on June 1, 2027, and 10 percent thereafter.

The Production Tax Credit and Investment Tax Credit inputs into the capital budgeting model, including the aforementioned input, will be updated to reflect the most current tax law at the time of the update.

(67) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(78) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be \$0.00/kW-month.

For 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, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of 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 calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, <u>New Capacity</u> <u>Resource Economic Life</u>, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. <u>For a</u> <u>new Capacity Resource with an expected New Capacity Resource Economic Life greater than the New</u> <u>Capacity Resource Economic Life used in Section III.A.21.1.2(b) to calculate the Offer Review Trigger</u> <u>Price for the corresponding technology type, the Project Sponsor shall provide sufficient documentation</u> <u>as described in Section III.A.21.2(b)(iv) to justify its expected New Capacity Resource Economic Life.</u> <u>The Internal Market Monitor shall consider the documentation provided.</u> The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and

general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. For a New Capacity Resource that has an expected New Capacity Resource Economic Life greater than the New Capacity Resource Economic Life used to calculate the Offer Review Trigger Price for the relevant technology type in Section III.A.21.1.2(b), the Project Sponsor shall provide evidence to support the expected New Capacity Resource Economic Life, including but not limited to, the asset life term for such resource as utilized in the Project Sponsor's financial accounting (e.g., independently audited financial statements); or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the Project Sponsor has not executed project financing for the resource (e.g.,

independent project engineer opinion or manufacturer's performance guarantee); or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. The Project Sponsor may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an expected New Capacity Resource Economic Life other than the New Capacity Resource Economic Life of similar projects. If there are multiple technology types in the New Capacity Resource, the New Capacity Resource Economic Life should reflect the weighted average of the New Capacity Resource Economic Life of each of the technology types. For a New Capacity Resource that is receiving an out-of-market revenue source and that is seeking a different Weighted Average Cost of Capital than the Net CONE reference unit, the Project Sponsor must submit documentation to demonstrate that the requested Weighted Average Cost of Capital is consistent with that of a resource not receiving out-of-market revenues. This documentation could include but not be limited to publicly available information sources or private information relevant to projects in North America that are not receiving out-of-market revenues. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a <u>mNew eCapacity <u>FR</u>esource composed of <u>mAssets</u> having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the <u>mAsset</u> technology types of the <u>mAssets</u> that comprise the <u>New Capacity FR</u>esource, based on the expected <u>capacity</u> contribution from each <u>mAsset</u> technology type <u>toward the FCA Qualified Capacity of the New <u>Capacity Resource</u>. Sufficient documentation must be included in the <u>New Capacity FR</u>esource's <u>New</u> <u>Capacity qQ</u>ualification <u>pPackage or New Demand Capacity Resource Qualification Package</u> to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.</u></u>

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

- (a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;
- (b) For each modeled import-constrained Capacity Zone, the greater of:
 - (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;
 - (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
- (c) For each modeled nested export-constrained Capacity Zone, the lesser of:
 - the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the nested export-constrained Capacity Zone plus, for each external interface connected to the nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;
 - (2) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;
- (d) For each modeled export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, the lesser of:
 - (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone, excluding the total FCA Qualified Capacity from Existing Generating Capacity Resources and Existing Demand Capacity Resources within a nested export-constrained Capacity Zone, plus, for each external interface connected to the export-constrained Capacity Zone that is not included in any nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, excluding the contribution from any nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

- (2) the Maximum Capacity Limit of the export-constrained Capacity Zone minus the contribution from any associated nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;
- (e) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of:
 - (1) the capacity transfer limit of the interface (net of tie benefits), and;
 - (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

- The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone; and
- (2) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

- (a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone or nested export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone or nested export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.
- (b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not

change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Capacity Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) 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; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any 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; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

- If
- The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than
- the annual capacity revenue from the Lead Market Participant's total FCA Qualified
 Capacity, including the FCA Qualified Capacity associated with the Permanent De-List
 Bid or Retirement De-List Bid, then
- iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

- iv. the Lead Market Participant's annual capacity revenue from the Lead Market
 Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity
 associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the
 product of (a) the Lead Market Participant's total FCA Qualified Capacity not including
 the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement
 De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not
 including the FCA Qualified Capacity associated with the Permanent De-List Bid or
 Retirement De-List Bid.
- v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.
- vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward

Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

Attachment N-1j

NEPOOL Clean Tariff

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 (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); (6) with respect to Demand Bids may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Demand Bids may contain multiple sets of quantity and price pairs for each hour); (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 each hour); and (7)

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 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, backto-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 or Non-Market Participant 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 Resource Economic Life is the number of years that is the lesser of (a) the period of time that a New Capacity Resource of a given technology type or types would reasonably be expected to

operate before the resource becomes unprofitable for at least two consecutive years, (b) the expected physical operating life of the resource, or (c) 35 years.

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.

Offer Review Trigger Prices are the prices specified in Section III.A.21.1 of Market Rule 1 associated with the submission of New Capacity Offers in the Forward Capacity Auction.

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 operation of the rights and responsibilities for the administration for the rights and responsibilities for the administration 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(1) 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 nondesignated 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 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 enduse 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 Sence of that action the Sence of that action 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 Sence of that action the Sence of that action 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 systemwide 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
 - 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/kWmonth;
 - (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
 - 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/kWmonth;
 - (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
 - 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/kWmonth

(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 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 $(1 \le m \le 5)$ submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, ..., p_m$, where $P_S > p_1 > p_2 > ... > p_m \ge P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, ..., q_m$. 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:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2$$

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)(ii). 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 Commissionapproved 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 Commissionapproved 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 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)(ii). 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 another bid for the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

Repowering. Offers and bids associated with a resource participating in the Forward Capacity (e) 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:

- 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 importconstrained 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 exportconstrained 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 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 importconstrained 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]. Referencesin this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward CapacityAuction Starting Price for the Forward Capacity Auction associated with the relevant CapacityCommitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is \$11.35/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is \$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) (except that the bonus tax depreciation adjustment described in Section

III.A.21.1.2(e)(5) shall not apply). 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 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 Capacity Commitment Periods, as elected pursuant to 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. 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 Commissionapproved 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 Commissionapproved 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 reliability 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.13.1.2.1.2.

(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.13.1.2.2.3 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 Clearing Price in the Rest-of-Pool 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), 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 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 exportconstrained 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 Restof-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.13.1.1.2 (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.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this *Appendix A*.

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this *Appendix A* shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this *Appendix A*. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this *Appendix A*.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor and External Market Monitor for and External Market Monitor is created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this *Appendix A*, the provisions of *Appendix A* shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III. A.17.3 are also part of the Participants Agreement and cannot be modified in either *Appendix A* or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this *Appendix A* are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this *Appendix A*). In the event the Internal Market Monitor or External Market Monitor of its

identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

- (b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.
- (c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the External Market Monitor shall perform the following functions:

- (a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this *Appendix A*, in accordance with the provisions of Section III.A.17 of this *Appendix A*.

- (c) Conduct evaluations and prepare reports on its own initiative or at the request of others.
- (d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this *Appendix A*.
- (f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.
- (g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this *Appendix A*, as appropriate.
- (h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the Internal Market Monitor shall perform the following functions:

- (a) Maintain *Appendix A* and consider whether *Appendix A* requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.
- (b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this *Appendix A*.
- (c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this *Appendix A*.
- (d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this *Appendix A*.
- (e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.
- (g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this *Appendix A*.
- (h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

- (i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this *Appendix A*.
- (j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this *Appendix A* are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:
 - (i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.
 - (ii) Uneconomic production from a Resource, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.
 - (iii) Anti-competitive Increment Offers and Decrement Bids, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this Appendix A.
 - (iv) Anti-competitive Demand Bids, which are addressed in Section III.A.10 of this AppendixA.
 - Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend *Appendix A* as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of

the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

- (k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:
 - (i) Anti-competitive gaming of Resources;
 - (ii) Conduct and market outcomes that are inconsistent with competitive markets;
 - (iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;
 - (iv) Actions in one market that affect price in another market;
 - (v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this *Appendix A*, interfere with efficient market operation, both short-run and long-run; and
 - (vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this *Appendix A*. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this *Appendix A*. If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

- (1) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.
- (m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with *Appendix B* of this Market Rule 1.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this *Appendix A* for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule 1 (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this *Appendix A*. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this *Appendix A*, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under *Appendix B* of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

- (a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:
- (b) Notwithstanding the foregoing or any other provision of this *Appendix A*, and as more fully described in Section III.B.3.2.6 of *Appendix B* to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this *Appendix A*, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this *Appendix A* or in *Appendix B* to this Market Rule 1.

III.A.3.Consultation Prior to Determination of Reference Levels for Physical and Financial
Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant. In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this Appendix A, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this *Appendix A* for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resourcespecific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer

or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus \$2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of	Months Precluded (starting	
Incidents	from most-recent incident)	
1	2	

2 or more	6
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III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

- (a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
- (b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,
- (c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
- (d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

- (a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
- (b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

- (a) all Supply Offer parameters shall be reviewed for economic withholding;
- (b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;
- (c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

- (a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;
- (b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

- (a) for purposes of the Real-Time Energy Market, the Resource is located on the importconstrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;
- (b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than \$25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

- (a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
- (b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or \$100/MWh, whichever is lower. Offer block prices below \$25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or \$100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or \$25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or \$25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

- i. local first contingency;
- ii. local second contingency;
- iii. VAR or voltage;
- iv. distribution (Special Constraint Resource Service);
- v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

- (a) If the Resource is starting from an offline state, the Start-Up Fee;
- (b) The sum of the No Load Fees for the Commitment Period; and
- (c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 "General Threshold Energy Mitigation" or III.A.5.5.2 "Constrained Area Energy Mitigation" is in effect for the following duration:

- (a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:
 - i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,
 - ii. for constrained area energy mitigation, the Resource is not located within a constrained area.
- (b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 "Constrained Area Energy Mitigation"), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 "Manual Dispatch Energy Mitigation" is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource's Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 "General Threshold Commitment Mitigation", III.A.5.5.5 "Constrained Area Commitment Mitigation", or III.A.5.5.6 "Reliability Commitment Mitigation" is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 "Start-Up Fee and No-Load Fee Mitigation" is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as

part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a startup state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

Market Participants are responsible for providing the Internal Market Monitor with all the information and data necessary for the Internal Market Monitor to calculate up-to-date Reference Levels for each of a Market Participant's Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

- (a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.
- (b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.
- (c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, Interruption Costs and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of an offer according to the following hierarchy, under which the first method that can be calculated is used:

- (a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
- (b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
- (c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

- (a) When in any hour the cost-based Reference Level is higher than either the accepted offerbased or LMP-based Reference Level.
- (b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
- (c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
- (d) For any Operating Day for which, during the previous 90 days:
 - the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
 - (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
- (e) When in any hour the incremental energy parameter of an offer, including adjusted offers pursuant to Section III.2.4, is greater than \$1,000/MWh.

For the purposes of this subsection:

- A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.
- ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.
- iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.
- iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.
- (e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.
- (f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:
 - (i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,
 - (ii) No-Load Fee or its corresponding fuel blends,
 - (iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,
 - (iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and
 - (v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

- (a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".
- (b) Costs must be documented.
- (c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible. All cost estimates, including opportunity cost estimates, must be quantified and analytically supported.
- (d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.
- (e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

- Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and
- ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy/Reduction:

(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

- (a) emissions limits;
- (b) water storage limits;
- (c) other operating permits that limit production of energy; and
- (d) reducing electricity consumption.

No-Load:

(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel,
emissions or variable and maintenance costs.

Start-Up/Interruption:

(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. [Reserved.]

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor the Energy Market as outlined below:

- (a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.
- (b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: (LMP real time / LMP day ahead) – 1. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.
- (c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between

the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as: $(LMP_{real time} / LMP_{day ahead}) - 1.$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

- (i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.
- Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.
- (iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations is greater than the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the

number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

- (a) [Reserved].
- (b) Section III.13.1.2.3.1.6.3 Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.
- (c) Section III.13.1.2.3.2 Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.
- (d) Section III.13.1.3.3A(d) Review by Internal Market Monitor of offers from Existing Import Capacity Resources.
- (e) Section III.13.1.3.5.6 Review by Internal Market Monitor of Offers from New Import Capacity Resources.
- (f) Section III.13.1.7 Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this *Appendix A*. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer *Appendix B* in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement. Article 5 of the form of Cost-of-Service Agreement in *Appendix I* to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Market Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.
III.A.15.1. Cost Recovery Request Following Capping.

If as a result of an offer being capped under Section III.1.9, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was capped, the Market Participant may, within 20 days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit an additional cost recovery request to the Internal Market Monitor.

A request under this Section III.A.15 may seek recovery of additional costs incurred for the duration of the period of time for which the Resource was operated at the cap.

III.A.15.1.1. Timing and Contents of Request.

Within 20 days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant requesting additional cost recovery under this Section III.A.15.1 shall submit to the Internal Market Monitor a request in writing detailing: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data, documentation and calculations for those costs; and (ii) an explanation of why the actual costs of operating the Resource exceeded the capped costs.

III.A.15.1.2. Review by Internal Market Monitor.

To evaluate a Market Participant's request, the Internal Market Monitor shall use the data, calculations and explanations provided by the Market Participant to verify the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, using the same standards and methodologies the Internal Market Monitor uses to evaluate requests to update Reference Levels under Section III.A.3 of Appendix A. To the extent the Market Participant's request warrants additional cost recovery, the Internal Market Monitor shall reflect that adjustment in the Resource's Reference Levels for the period covered by the request. The ISO shall then re-apply the cost verification and capping formulas in Section III.1.9 using the updated Reference Levels to re-calculate the adjustments to the Market Participant's offers required thereunder, and then shall calculate additional cost recovery using the adjusted offer values.

Within 20 days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the Market Participant's request, detailing (i) the extent to which it agrees with the request with supporting explanation, and (ii) a calculation of the additional cost recovery. Changes to

credits and charges resulting from an additional cost recovery request shall be included in the Data Reconciliation Process.

III.A.15.1.3. Cost Allocation.

The ISO shall allocate charges to Market Participants for payment of any additional cost recovery granted under this Section III.A.15.1 in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.15.2. Section 205 Filing Right.

If either

(a) as a result of mitigation applied to a Resource under this *Appendix A* for all or part of one or more Operating Days, or

(b) in the absence of mitigation, as a result of a request under Section III.A.15.1 being denied in whole or in part,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was mitigated or the Section III.A.15.1 request was denied, the Market Participant may submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. For filings to address cost recovery under Section III.A.15.2(a), the filing must be made within sixty days of receipt of the first Invoice issued containing credits or charges for the applicable Operating Day. For filings to address cost recovery under Section III.A.15.2(b), the filing must be made within sixty days of receipt of the first Invoice issued that reflects the denied request for additional cost recovery under Section III.A.15.1.

A request under this Section III.A.15.2 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having a Section III.A.15.1 request denied, costs incurred for the duration of the period of time addressed in the Section III.A.15.1 request.

III.A.15.2.1. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data

and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource, as reflected in the original offer and to the extent not recovered under Section III.A.15.1, exceeded the costs as reflected in the capped offer; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.2.2. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the applicable Invoice, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15.2 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2.1 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15.2 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.2.

III.A.15.2.3. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in *Appendix D* to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

• Imposition of a mitigation remedy.

• Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this *Appendix A*, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

- (a) the opportunity costs associated with Demand Reduction Offers;
- (b) the accuracy of Demand Response Baselines;
- (c) the method used to achieve a demand reduction, and;
- (d) the accuracy of metered demand reported to the ISO.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this Appendix A and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this Appendix A.

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this *Appendix A*.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of *Appendix A*. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

- Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.
- (ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.
- (iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.
- (iv) Review and assessment of the effectiveness of *Appendix A* and the administration of *Appendix A* by the Internal Market Monitor for consistency and compliance with the terms of *Appendix A*.
- Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

- (a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;
- (b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;
- (c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,
- (d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). With respect to state regulatory bodies and state attorneys general ("authorized state agencies"), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government

agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as *Exhibit 5*.

III.A.18.2. Additional Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of *Appendix A*, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

- (B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information
 - The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);
 - (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
 - (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
 - (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
 - (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;
 - (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
 - (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

- (A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.
- (B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information.
 - (1) A detailed narrative describing the perceived market design flaw(s);
 - (2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;
 - (3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;
 - (4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the Capacity Commitment Period beginning on June 1, 2025 shall be as follows:

Generating Capacity Resources	
Technology Type	Offer Review Trigger Price (\$/kW-month)
Simple Cycle Combustion Turbine	\$5.355
Combined Cycle Gas Turbine	\$9.811
On-Shore Wind	\$0.000
Off-Shore Wind	\$0.000
Energy Storage Device – Lithium Ion Battery	\$2.601
Photovoltaic Solar	\$0.000

Demand Capacity Resources		
Technology Type	Offer Review Trigger Price (\$/kW-month)	
Load Management (Commercial / Industrial)	\$0.750	
Previously Installed Distributed Generation	\$0.750	
New Distributed Generation	Based on generation technology type	
On-Peak Solar	\$5.414	

Other Resources		
All other technology types	Forward Capacity Auction Starting Price	

Where one or more Assets sharing a point of interconnection register as a New Capacity Resource that does not include all of the Assets sharing the point of interconnection, the Offer Review Trigger Price for the New Capacity Resource will be assigned according only to the Asset or Assets contributing to the FCA Qualified Capacity of the New Capacity Resource.

Where a New Capacity Resource is composed of Assets having different technology types (including, but not limited to, a photovoltaic solar generator sharing a point of interconnection with an energy storage device participating in the energy market as one or more Assets and participating in the capacity market as a single New Capacity Resource), the New Capacity Resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For 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, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus \$0.01/kW-month. For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. 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.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties), over the New Capacity Resource Economic Life of the project.

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy

Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) For the simple cycle combustion turbine and combined cycle gas turbine technology types, each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114). For all other Generating Capacity Resource technology types, each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the levelized cost of energy for that technology as published by Bloomberg.

(2) For each line item in (1) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices reflected in the table in Section III.A.21.1.1. The value of each line item associated with capital costs in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 will be adjusted by the relevant multiplier.

(3) The energy and ancillary services offset values for gas technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE for the first five trading days in February, for each month of the Capacity Commitment Period to which the updated value will apply.

The energy and ancillary services offset values for non-gas technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Massachusetts Hub Day-Ahead

Peak electricity prices, as published by ICE for the first five trading days in February, for each month of the Capacity Commitment Period to which the updated value will apply.

(4) Renewable energy credit values in the capital budgeting model shall be updated based on the first MA Class 1 REC prices published in February for the five vintages closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(5) The bonus tax depreciation adjustment included in the financial model for the Offer Review Trigger Prices (which is 40 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 20 percent for the Capacity Commitment Period beginning on June 1, 2026, and zero for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(6) The Investment Tax Credit input into the capital budgeting model for the Photovoltaic Solar Generating Capacity Resource shall be 26 percent for the Capacity Commitment Period beginning on June 1, 2026, 22 percent for the Capacity Commitment Period beginning on June 1, 2027, and 10 percent thereafter.

The Production Tax Credit and Investment Tax Credit inputs into the capital budgeting model, including the aforementioned input, will be updated to reflect the most current tax law at the time of the update.

(7) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection(e) will be published on the ISO's web site.

(8) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be \$0.00/kW-month.

For 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, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of 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 calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, New Capacity Resource Economic Life, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. For a new Capacity Resource with an expected New Capacity Resource Economic Life greater than the New Capacity Resource Economic Life used in Section III.A.21.1.2(b) to calculate the Offer Review Trigger Price for the corresponding technology type, the Project Sponsor shall provide sufficient documentation as described in Section III.A.21.2(b)(iv) to justify its expected New Capacity Resource Economic Life. The Internal Market Monitor shall consider the documentation provided. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. For a New Capacity Resource that has an expected New Capacity Resource Economic Life greater than the New Capacity Resource Economic Life used to calculate the Offer Review Trigger Price for the relevant technology type in Section III.A.21.1.2(b), the Project Sponsor shall provide evidence to support the expected New Capacity Resource Economic Life, including but not limited to, the asset life term for such resource as utilized in the Project Sponsor's financial accounting (e.g., independently audited financial statements); or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the Project Sponsor has not executed project financing for the resource (e.g., independent project engineer opinion or manufacturer's performance guarantee); or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. The Project Sponsor may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an expected New Capacity Resource Economic Life other than the New Capacity Resource Economic Life of similar projects. If there are multiple technology types in the New Capacity Resource, the New

Capacity Resource Economic Life should reflect the weighted average of the New Capacity Resource Economic Life of each of the technology types. For a New Capacity Resource that is receiving an out-of-market revenue source and that is seeking a different Weighted Average Cost of Capital than the Net CONE reference unit, the Project Sponsor must submit documentation to demonstrate that the requested Weighted Average Cost of Capital is consistent with that of a resource not receiving out-of-market revenues. This documentation could include but not be limited to publicly available information sources or private information relevant to projects in North America that are not receiving out-of-market revenues. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a New Capacity Resource composed of Assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the Asset technology types of the Assets that comprise the New Capacity Resource, based on the expected contribution from each Asset technology type toward the FCA Qualified Capacity of the New Capacity Resource. Sufficient documentation must be included in the New Capacity Resource's New Capacity Qualification Package or New Demand Capacity Resource Qualification Package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

- (a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;
- (b) For each modeled import-constrained Capacity Zone, the greater of:

- (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;
- (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
- (c) For each modeled nested export-constrained Capacity Zone, the lesser of:
 - the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the nested export-constrained Capacity Zone plus, for each external interface connected to the nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;
 - (2) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;
- (d) For each modeled export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, the lesser of:
 - (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone, excluding the total FCA Qualified Capacity from Existing Generating Capacity Resources and Existing Demand Capacity Resources within a nested export-constrained Capacity Zone, plus, for each external interface connected to the export-constrained Capacity Zone that is not included in any nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, excluding the contribution from any nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;
 - (2) the Maximum Capacity Limit of the export-constrained Capacity Zone minus the contribution from any associated nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;
- (e) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of:
 - (1) the capacity transfer limit of the interface (net of tie benefits), and;

(2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

- The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone; and
- (2) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

- (a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone or nested export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone or nested export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.
- (b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Capacity Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) 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; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any 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; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified

Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than

- the annual capacity revenue from the Lead Market Participant's total FCA Qualified
 Capacity, including the FCA Qualified Capacity associated with the Permanent De-List
 Bid or Retirement De-List Bid, then
- iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

- iv. the Lead Market Participant's annual capacity revenue from the Lead Market
 Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity
 associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the
 product of (a) the Lead Market Participant's total FCA Qualified Capacity not including
 the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement
 De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not
 including the FCA Qualified Capacity associated with the Permanent De-List Bid or
 Retirement De-List Bid.
- v. The Lead Market Participant's annual capacity revenue from the Lead Market
 Participant's total FCA Qualified Capacity including the FCA Qualified Capacity
 associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the
 product of (a) the Lead Market Participant's total FCA Qualified Capacity including the
 FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including
 the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement
 De-List Bid.
- vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates. For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.