September 11, 2020

<u>VIA ELECTRONIC FILING</u>

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 Participants Committee*, Docket No. ER20-___-000, Filing of Improvements to the Methodology for Reconstitution of Passive Demand Resources in the Gross Load Forecast

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act,[1] ISO New England Inc. (the "ISO"), joined by the New England Power Pool ("NEPOOL") Participants Committee[2] (together, the "Filing Parties"),[3] hereby electronically submits this transmittal letter and revisions to the Tariff ("Tariff Changes") to improve the methodology that the ISO uses to reconstitute On-Peak Demand Resources[4] and Seasonal Peak Demand Resources[5] (collectively, for purposes of this

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[1] 16 U.S.C. § 824d.

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

[3] Under New England's Regional Transmission Organization ("RTO") arrangements, the rights to make this filing are the ISO's. NEPOOL, which pursuant to the Participants Agreement provides the sole Participant Processes for advisory voting on ISO matters, supported the changes reflected in this filing and, accordingly, joins in the filing.

[4] Under Section I.2.2 of the Tariff, 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."

[5] Under Section I.2.2 of the Tariff, a 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."

filing letter, "Passive Demand Resources")[6] in the long-term gross load forecast (referred to in this filing letter as the "gross load forecast"). The changes are supported by the Testimony of Jonathan Black, the ISO's Manager of Load Forecasting (the "Black Testimony"). The Black Testimony is solely sponsored by the ISO.

While the ISO is not proposing modifications to the methodology it uses to reconstitute active demand resources in the gross load forecast,[7] as described in Section V.B of this filing, the ISO is streamlining the Tariff language related to that reconstitution. Finally, as explained in Section V.C of this filing, the ISO is deleting obsolete language in Section III.12.8 (b), and making conforming, non-substantive changes in the preamble of Section III.12.8 – Load Modeling Assumptions.

I. REQUESTED EFFECTIVE DATE

The ISO requests that the Tariff Changes submitted in this filing become effective on November 10, 2020. This effective date will allow the ISO to use the improved methodology for reconstitution of Passive Demand Resources in the development of the gross load forecast for 2021.

II. DESCRIPTION OF THE FILING PARTIES; COMMUNICATIONS

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

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[6] Passive Demand Resources do not actively participate in energy markets. Their participation is limited to the Forward Capacity Market ("FCM"). Rather than being dispatched, Passive Demand Resources reduce demand once the respective measures are installed.

[7] Active demand resources participate in energy markets by offering demand reductions, which the ISO dispatches based on price. Active demand resources are currently defined in the Tariff as Demand Response Resources. A Demand Response Resource may choose to participate in the FCM and, if it does so, it falls under the definition of Active Demand Capacity Resource in Section I.2.2 of the Tariff, which provides that an 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 [FCM] to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1." Thus, active demand resources participate in the energy market and may or may not participate in the FCM. Reconstitution in the gross load forecast is done for all active demand resources.

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 500 members. The Participants include all of the electric utilities rendering or receiving service under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, demand resource providers, developers and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission,[8] the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, "NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff."

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

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[8] *ISO New England Inc., et al.*, 109 FERC ¶ 61,147 (2004).

III. STANDARD OF REVIEW

The Tariff Changes are being submitted pursuant to Section 205, which "gives a utility the right to file rates and terms for services rendered with its assets."[9] Under Section 205, the Commission "plays 'an essentially passive and reactive role'"[10] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[11] 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."[12] The changes proposed herein "need not be the only reasonable methodology, or even the most accurate."[13] 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.[14]

IV. BACKGROUND

Since the beginning of the Forward Capacity Market ("FCM"), Passive Demand Resources have been allowed to participate in the market as supply-side resources, acquiring Capacity Supply Obligations ("CSOs") in the same manner as other supply-side resources. In addition, each year, the ISO develops a gross load forecast using historical loads as one of its inputs. Historical loads must properly account for the load reductions from Passive Demand Resources that participate as supply-side resources in the FCM. Otherwise, those resources would be double-counted (both as load reductions and as capacity supply resources). Accordingly, in developing the gross load forecast, pursuant to Section III.12.8 (d) of the Tariff, the ISO must "reconstitute" (*i.e.,* add back) the demand savings achieved by Passive Demand Resources that participate in the FCM as supply-side resources. "Reconstitution" is purely an accounting mechanism intended to align demand assumptions represented by the load forecast with Passive Demand Resources' participation as supply-side resources in the FCM.

Currently, Section III.12.8 (d), which provides for the reconstitution of Passive Demand Resources in the gross forecast, states:

> Any realized Demand Capacity Resource reductions in the historical period that received [FCM] payments for these reductions, or Demand Capacity Resource reductions that are expected to receive [FCM] payments by participating in the

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

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

[11] *Id.* at 9.

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

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

[14] *Cf. Southern California Edison Co., et al,* 73 FERC ¶ 61,219 at 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*)).

> upcoming Forward Capacity Auction [("FCA")] or having cleared in a previous FCA, shall be added back into the appropriate historical loads to ensure that such resources are not reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement [("ICR")], Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period.

Starting with the 2010 gross load forecast, to implement Section III.12.8 (d) of the Tariff for Energy Efficiency ("EE") resources (which have historically constituted more than 91% of Passive Demand Resources since the inception of the FCM),[15] the ISO has used the performance data that each EE program administrator submits to the ISO. Specifically, each EE program administrator enters monthly MW values into the ISO's EE measures database ("EEM").[16] The ISO uses those monthly demand values, which reflect demand reductions during seasonal performance hours, to estimate the amount of monthly energy and hourly demand needed for EE reconstitution.[17]

The ISO had expected that using EE performance (*i.e.,* the amount of total EE measures installed) to reconstitute Passive Demand Resources in the gross load forecast would yield a reconstituted MW value of EE resources that would be commensurate with the MW values of the CSOs that EE resources acquired in the FCM. However, in recent years, the ISO has observed that EE program administrators install and report EE measures in quantities that exceed the CSOs that EE resources have acquired in the FCM. There is no way for the ISO to determine which measures are installed to meet CSOs and which measures are installed in excess of CSOs. For this reason, the amount of Passive Demand Resources reconstituted in developing the gross load forecast has exceeded the amount of CSOs that Passive Demand Resources have acquired in the FCM.[18] The changes in the load forecast that result from application of the proposed methodology to better account for FCA CSOs (which is explained below and in the Black Testimony) to the 2020 Forecast Report of Capacity, Energy, Loads, and Transmission ("CELT") illustrate this excess. Specifically, application of the proposed methodology shows a 657 MW reduction in the gross load forecast for summer 2020, and a 1,355 MW reduction in the gross load forecast for summer 2029.[19]

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[15] Black Testimony at 7.

[16] While EEM was not available since the beginning of FCM, all the data that program administrators have provided since the beginning of FCM is now reflected in EEM.

[17] Black Testimony at 8.

[18] *Id.* at 9.

[19] *Id.* at 16. The gross load forecast is an assumption used in the calculation of the ICR and related values, including the demand curves used in the FCA. As such, a decrease in the gross load forecast generally results in a decrease in the ICR, all other assumptions being equal.

In addition, while relatively few EE measures have expired[20] up to the 2019-2020 Capacity Commitment Period, a significant number of EE measures are set to expire over the FCM horizon (*i.e.,* over subsequent Capacity Commitment Periods associated with already-completed FCAs that are beyond the end of the historical reconstitution period used in developing the ISO's load forecast). However, these trends over the FCM horizon are not well captured by the current methodology, which relies on historical EE performance alone. Moreover, measure expiration is factored directly into the calculation of the Qualified Capacity values for FCM participation of existing Passive Demand Resources.[21] Therefore, because the objective is for the Qualified Capacity of cleared Passive Demand Resources and reconstitution amounts to align, measure expiration over the FCM horizon should also be factored into the gross load forecast.[22]

Based on the foregoing considerations, the ISO has determined that the reconstitution methodology for Passive Demand Resources needs to be revised to better reflect the amount of demand resources that participate in the FCM as supply-side resources. As such, in this filing, the ISO is proposing an improved reconstitution methodology for Passive Demand Resources. In addition, although the methodology for reconstitution of active demand resources is not being modified, this filing includes Tariff changes that streamline the provisions related to reconstitution of active demand resources in Section III.12.8 (a) of the Tariff. Finally, in this filing, the ISO is deleting obsolete language in Section III.12.8 (b), and making conforming, non-substantive changes in the preamble of Section III.12.8 – Load Modeling Assumptions.

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[20] Section III.13.1.4.1 of the Tariff provides that "[a] Demand Resource may continue to offer capacity into [FCAs] and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life." Thus, an EE measure expires when it reaches the end of its Measure Life, at which point it can no longer participate in the FCM as a capacity resource. Measure Life is defined in Section I.2.2 of the Tariff as "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 [FCA] 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."

[21] Passive Demand Resources that have cleared in an auction and can no longer participate as new capacity are existing Passive Demand Resources.

[22] Black Testimony at 9-10.

V. DESCRIPTION OF PROPOSED TARIFF CHANGES

A. Tariff Changes Related to the Proposed Methodology for Reconstitution of Passive Demand Resources

As explained below and in the Black Testimony, the proposed methodology for reconstitution of Passive Demand Resources includes a procedure to account for CSOs that Passive Demand Resources acquire in the FCA, as well as adjustments to account for the differences between the CSOs that Passive Demand Resources acquire in the FCA and the CSOs that those resources acquire in the annual reconfiguration auctions ("ARAs").[23]

1. Accounting of CSOs Acquired in the FCA

Instead of using the data that each EE program administrator enters into EEM to reconstitute Passive Demand Resources in the gross load forecast, under the proposed methodology, the ISO will use the total CSOs acquired by Passive Demand Resources in each FCA to estimate Passive Demand Resources' FCA participation in the upcoming auction.

Specifically, the ISO will develop trend lines between the points in time when summer and winter MW values for Passive Demand Resources are assumed to be zero (*i.e.* June 1, 2006 for summer and December 1, 2006 for winter) and the points in time when summer and winter MW values are reflected by the CSOs that Passive Demand Resources acquired in the most recent FCA for, respectively, June 1 (summer) and December 1 (winter) of the associated Capacity Commitment Period. June 1, 2006 and December 1, 2006 are the appropriate dates to use as the starting points for the trend lines because the resulting reconstitution reflects the long-term average of Passive Demand Resources' participation in all completed FCAs. This is important given that the amount of CSOs that clear as new capacity in each FCA is unpredictable and can vary significantly between successive auctions, making longer-term averages more consistent and reliable. Furthermore, use of the entire historical period to develop the reconstitution trend lines ensures that the proposed methodology generalizes well for all portions of the region (*i.e.,* the six New England states) for which the ISO is required to develop forecasts.[24] As Mr. Black explains in his testimony, to determine the summer and winter MW values to be added back into historical loads, the ISO will apply the resulting participation trends to, respectively, the summer months (*i.e.* April through November), and the winter months (*i.e.* December through March), in all the historical years covered by the trend lines.[25]

The CSOs acquired by Passive Demand Resources in the most recently conducted FCA reflect the cumulative EE measure expiration over several upcoming Capacity Commitment

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[23] The new methodology for the reconstitution of Passive Demand Resources explained below is reflected in the new language that is being added in Section III.12.8 (d) of the Tariff. Accordingly, the current language in that section is being deleted, as it reflects a methodology that will no longer be used.

[24] Black Testimony at 13-14.

[25] *Id.* at 11-13.

Periods that are beyond the historical reconstitution period used in developing the gross load forecast. As such, using these CSO values captures the effects of future EE measure expiration in the load forecast.[26] In addition, the new methodology ensures that reconstituted Passive Demand Resources are appropriately embedded in the gross load forecast by creating a smooth historical reconstitution time series. Such smoothing, accomplished by the proposed methodology, also enables the use of the CSOs from the most recently conducted FCA, which is associated with a Capacity Commitment Period that is beyond the historical reconstitution period used in developing the gross load forecast. Moreover, by calibrating to the CSOs acquired by Passive Demand Resources in the most recently completed FCA, the proposed reconstitution methodology results in improved accounting for: (1) the amount of Passive Demand Resources that participate in the FCA (which does not include EE installations in excess of the resources' CSOs); and (2) expired EE measures that are no longer participating as supply in the FCM.[27]

As Mr. Black describes, the improved methodology results in a reconstitution trend for Passive Demand Resources that exhibits a lower level and slope than that of the reconstitution of Passive Demand Resources based on the current methodology, and will therefore result in a lower gross load forecast. This is because the reconstitution will no longer include EE installations in excess of the resources' CSOs, and is net of cumulative EE expiring measures over the FCM horizon that no longer participate as supply in FCM up through the most recently held FCA. Both of these factors will become embedded as load reductions in the gross load forecast as a result of the improved methodology.[28]

2. Adjustments to account for the differences between CSOs acquired in the FCA and CSOs acquired in the ARAs

Currently, the same load forecast is used for the FCA and the ARAs. However, the ISO has observed that Passive Demand Resources clear different amounts of CSOs in each of the ARAs than the amount of CSOs they clear in the FCA for the corresponding Capacity Commitment Period. To account for these differences, and in recognition that the proposed reconstitution methodology calibrates the forecast to the amount of CSOs that Passive Demand Resources clear in the FCA, in this filing, the ISO also proposes to develop unique forecast adjustments tailored for each of the upcoming ARAs and their associated Capacity Commitment Periods.

As Mr. Black explains in detail, to determine the adjustments to be made to forecasted loads, the ISO will estimate the CSOs that will be acquired by Passive Demand Resources in the upcoming ARAs ("ARAx") using historical ARA and FCA CSO data. This estimation will use the average differences between the two most recent ARAx CSOs and those of the FCAs for the corresponding Capacity Commitment Periods. The ISO will then calculate the adjustments

[26] Because the FCA is held in February of each year, it occurs prior to the publication of the annual CELT. The CELT is published by May 1 of each year.

[27] Black Testimony at 14-15.

[28] *Id*.

based on the difference between the estimated ARAx CSOs and the Passive Demand Resources embedded in the gross load forecast of the appropriate Capacity Commitment Period.[29] The proposed framework for adjusting the gross load forecast results in a load forecast that is better calibrated to the differences in the amount of Passive Demand Resources participating in each of the ARAs than the current reconstitution methodology, which includes no such accounting.

B. Tariff Changes that Streamline the Tariff Language for Reconstitution of Active Demand Resources

From the beginning of the FCM, the ISO has reconstituted active demand resources in the gross load forecast by adding back into historical loads the metered MW demand reduction of Demand Response Resources.[30] The ISO is not proposing to change this methodology. However, the current language in Section III.12.8 (a), which provides for the reconstitution of active demand resources in the gross load forecast, is being streamlined in this filing to more clearly and concisely reflect that methodology. Specifically, by using the defined term Demand Response Resources, there is no longer a need to refer to Demand Capacity Resources that do not qualify or participate in the FCA. This is because Demand Response Resources are dispatched by the ISO, but may or may not participate in the FCM.

C. Deletion of Obsolete Provision and Conforming, Non-Substantive Changes in the Preamble of Section III.12.8 – Load Modeling Assumptions

The language in Section III.12.8 (b) of the Tariff became obsolete when the price-responsive demand construct became effective.[31] Specifically, Section III.12.8 (b) implies that Demand Capacity Resources (which are demand resources that acquire CSOs in the FCM) are the only demand resources to be reconstituted in the load gross load forecast. This was appropriate when all active and passive demand resources, including active demand resources that were dispatched by the ISO to avoid or relieve real-time capacity deficiencies, could participate only in the FCM. However, under the price-responsive demand construct, active demand resources (*i.e.,* Demand Response Resources) must participate in the energy markets and are dispatched by the ISO based on price. Demand Response Resources do not need to acquire CSOs in the FCM. Therefore, Section III.12.8 (b) is no longer accurate because it uses a term

[29] Additional details are included in the Black Testimony at 17-23.

[30] Under Section I.2.2 of the Tariff, a 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". A 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 Section III.8.1.1."

[31] The price-responsive demand construct was incorporated in the Tariff to comply with FERC Order No. 745 and became effective on June 1, 2018.

that does not include Demand Response Resources that do not have a CSO, which have to be reconstituted in the gross load forecast.[32]

In addition, as explained in this filing letter, the new methodology for reconstitution of Passive Demand Resources is based on the CSOs acquired by those resources. However, Section III.12.8 (b) includes language for reconstitution of Demand Capacity Resources (which includes Passive Demand Resources) that do not have CSOs. Therefore, Section III.12.8 (b) conflicts with the new methodology for reconstitution of Passive Demand Resources and, as such, it cannot remain in the Tariff. For the foregoing reasons, Section III.12.8 (b) of the Tariff is being deleted in this filing and, going forward, it will be shown as "Reserved."

Finally, the purpose of reconstitution in the gross load forecast is currently stated in Section III.12.8 (d), which only applies to Passive Demand Resources. The purpose (*i.e.,* to ensure that Demand Response Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources are not reflected as reductions in the load forecast) is being moved to the preamble of Section III.12.8, so that it applies to both active demand resources and Passive Demand Resources. With this change, the defined terms in the preambles are conformed to the defined terms used in the Tariff language in Sections III.12.8 (a) and (d).[33]

VI. STAKEHOLDER PROCESS

On July 21, 2020, the NEPOOL Reliability Committee voted to recommend that the Participants Committee support the Tariff Changes by a vote of 60.62% in favor. On September 3, 2020, the Participants Committee supported the Tariff Changes with a vote of 68.22% in favor.

VII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the Tariff Changes do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations.[34] Notwithstanding the request for waiver, the Filing Parties submit 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:

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[32] As already explained above, by using the defined term "Demand Response Resources," the new language in Section III.12.8 (a) reflects the methodology that the ISO has always used for reconstituting active demand resources (*i.e.* reconstituting all active demand resources that are dispatched by the ISO).

[33] The ISO is also revising the language in the preamble of Section III.12.8 by using the active voice.

[34] 18 C.F.R. § 35.13 (2018).

- This transmittal letter;
- Blacklined Tariff sections reflecting the revision submitted in this filing;
- Clean Tariff sections reflecting the revision submitted in this filing;
- Testimony of Jonathan Black; 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 I above, the Filing Parties request that the changes become effective on November 10, 2020.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are available on the ISO's website at: https://www.iso-ne.com/participate/participant-asset-listings/directory?id=1&type=committee. A copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, the New England Conference of Public Utility Commissioners, Inc., and to the New England States Committee on Electricity. Their names and addresses are shown in the attached listing. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified in the listing to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

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

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

35.13(b)(6) – The ISO's approval of the changes is evidenced by this filing. The changes reflect the results of the Participant Processes required by the Participants Agreement and reflect the support of the Participants Committee.

35.13(b)(7) – Neither the ISO nor NEPOOL has 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 changes submitted 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 revision filed herein.

VIII. CONCLUSION

For the reasons discussed in this transmittal letter, the Filing Parties request that the Commission accept the Tariff Changes, without modification, to become effective on November 10, 2020.

Respectfully submitted,

ISO NEW ENGLAND INC.

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Attachments

III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

Prior to each Forward Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction in accordance with this Section III.12.1.

The ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period. The Installed Capacity Requirement shall be determined assuming all resources pursuant to Sections III.12.7 and III.12.9 will be deliverable to meet the forecasted demand determined pursuant to Section III.12.8.

If the Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Installed Capacity Requirement. The modeling assumptions used in determining the Installed Capacity Requirement are specified in Sections III.12.7, III.12.8 and III.12.9. For the purpose of this Section III.12, a "resource" shall include generating resources, demand resources, and import capacity resources eligible to receive capacity payments in the Forward Capacity Market.

III.12.1.1. System-Wide Marginal Reliability Impact Values.

Prior to each Forward Capacity Auction, the ISO shall determine the system-wide Marginal Reliability Impact of incremental capacity at various capacity levels for the New England Control Area. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used in determining the Installed Capacity Requirement.

III.12.2. Local Sourcing Requirements and Maximum Capacity Limits.

Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section

III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction.

The ISO shall use consistent assumptions and standards to establish a resource's electrical location for purposes of qualifying a resource for the Forward Capacity Market and for purposes of calculating Local Sourcing Requirements and Maximum Capacity Limits. The methodology used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.2.1 and III.12.2.2, respectively. The modeling assumptions used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.5, III.12.6, III.12.7, III.12.8 and III.12.9.

III.12.2.1. Calculation of Local Sourcing Requirements for Import-Constrained Capacity Zones.

For each import-constrained Capacity Zone, the Local Sourcing Requirement shall be the amount needed to satisfy the higher of: (i) the Local Resource Adequacy Requirement as determined pursuant to Section III.12.2.1.1; or (ii) the Transmission Security Analysis Requirement as determined pursuant to Section III.12.2.1.2.

III.12.2.1.1. Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

(a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the import-constrained side of the interface, if any; and (ii) the rest of the New England Control Area which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits on the unconstrained side of the interface, if any.

(b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Local Resource Adequacy Requirement for the import-constrained Capacity Zone Z shall be determined in accordance with the following formula:

LRA_Z = $Resources_z$ +$Proxy\ Units_z$ – (Proxy Units $Adjustment_z(1\text{-}FOR_z)$)-(Firm Load $Adjustment_z(1\text{-}FOR_z)$)

In which:

LRA_Z	=	MW of Local Resource Adequacy Requirement for Capacity Zone Z;
$Resources_z$	=	MW of resources electrically located within Capacity Zone Z, including import Capacity Resources on the import-constrained side of the interface, if any;
$Proxy\ Units_z$	=	MW of proxy unit additions in Load Zone Z;
Firm Load $Adjustment_z$	=	MW of firm load added (or subtracted) within Capacity Zone Z to make the LOLE of the New England Control Area equal to 0.105 days per year; and
FOR_z	=	Capacity weighted average of the forced outage rate modeled for all resources within Capacity Zone Z, including and proxy unit additions to Capacity Zone Z.
Proxy Units Adjustment	=	MW of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1

days/year.

To determine the Local Resource Adequacy Requirement, the firm load is adjusted within Capacity Zone Z until the LOLE of the New England Control Area reaches 0.105 days per year. The LOLE of 0.105 days per year includes an allowance for transmission related LOLE of 0.005 days per year associated with each interface. As firm load is added to (or subtracted from) Capacity Zone Z, an equal amount of firm load is removed from (or added to) the rest of New England Control Area.

III.12.2.1.2. Transmission Security Analysis Requirement.

A Transmission Security Analysis shall be used to determine the requirement of the zone being studied, and shall include the following features:

(a) The ISO shall perform a series of transmission load flow studies and/or a deterministic operable capacity analysis targeted at determining the performance of the system under stressed conditions, and at developing a resource requirement sufficient to allow the system to operate through those stressed conditions.

(b) The Transmission Security Analysis Requirement shall be set at a level sufficient to cover most reasonably anticipated events, but will not guarantee that every combination of obligated resources within the zone will meet system needs.

(c) In performing the Transmission Security Analysis, the ISO may establish static transmission interface transfer limits, as identified pursuant to Section III.12.5, as a reasonable representation of the transmission system's capability to serve load with available existing resources.

(d) The Transmission Security Analysis may model the entire New England system and individual zones, for both the first contingency (N-1) and second contingency (N-1-1) conditions. First contingency conditions (N-1) shall include the loss of the most critical generator or most critical transmission element with respect to the zone. Second contingency conditions (N-1-1) shall include both: (i) the loss of the most critical generator with respect to the zone followed by the loss of the most critical transmission element ("Line-Gen"); and (ii) the loss of the most critical transmission element followed by the loss of the next most critical transmission element ("Line-Line") with respect to the zone.

III.12.2.1.3. Marginal Reliability Impact Values for Import-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each import-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) shall be reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero.

III.12.2.2. Calculation of Maximum Capacity Limit for Export-Constrained Capacity Zones.

For each export-constrained Capacity Zone, the Maximum Capacity Limit shall be calculated using the following method:

(a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the export-constrained side of the interface, if any; and (ii) the rest of the New England Control Area, which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits to the rest of the New England Control Area, if any.

(b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Maximum Capacity Limit for the export-constrained Capacity Zone Y shall be determined in accordance with the following formula:

$$\text{Maximum Capacity Limit}_Y = \text{ICR} - \text{LRA}_{RestofNewEngland}$$

In which:

Maximum Capacity Limit$_Y$ = Maximum MW amount of resources , including Import Capacity Resources on the export-constrained side of the interface, if any, that can be procured in the export-constrained Capacity Zone Y to meet the Installed Capacity Requirement;

ICR = MW of Installed Capacity Requirement for the New England Control Area, determined in accordance with Section III.12.1; and

LRA$_{RestofNewEngland}$ = MW of Local Sourcing Requirement for the rest of the New England Control Area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Section III.12.2.1.

III.12.2.2.1. Marginal Reliability Impact Values for Export-Constrained Capacity Zones.
Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each export-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit.

III.12.3 Consultation and Filing of Capacity Requirements.
At least two months prior to filing the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves with the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves

for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act 90 days prior to the Forward Capacity Auction for the Capacity Commitment Period. The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given FCA, any new Capacity Zone must have received approval from the Commission prior to the Existing Capacity Qualification Deadline of the applicable FCA.

III.12.4. Capacity Zones.

For each Forward Capacity Auction, the ISO shall, using the results of the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K, determine the Capacity Zones to model as described below, and will include such designations in its filing with the Commission pursuant to Section III.13.8.1(c):

(a) The ISO shall model in the Forward Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit is less than the sum of the existing Qualified Capacity and proposed new capacity that could qualify to be procured in the export constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface.

(b) The ISO shall model in the Forward Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the second contingency transmission capability results in a line-line Transmission Security Analysis Requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, that is greater than the existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model out-of-service all Retirement De-List Bids and Permanent De-List Bids (including any received for the current Forward Capacity Auction at the time of this calculation), substitution auction demand bids submitted for the current Forward Capacity Auction, rejected for reliability Static De-List Bids from the most recent previous Forward Capacity Auction, and rejected for reliability Dynamic De-List Bids from the most recent previous Forward Capacity Auction.

(c) Adjacent Load Zones that are neither export-constrained nor import-constrained shall be modeled together as the Rest of Pool Capacity Zone in the Forward Capacity Auction.

III.12.4A. Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location of Active Demand Capacity Resources. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction, and those Dispatch Zones shall remain in place through the end of the Capacity Commitment Period for which they were established. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.12.5. Transmission Interface Limits.

Transmission interface limits, used in the determination of Local Sourcing Requirements, shall be determined pursuant to ISO Tariff Section II, Attachment K using network models that include all resources, existing transmission lines and proposed transmission lines that the ISO determines, in accordance with Section III.12.6, will be in service no later than the first day of the relevant Capacity Commitment Period. The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

III.12.6. Modeling Assumptions for Determining the Network Model.

The ISO shall determine, in accordance with this Section III.12.6, the generating units and transmission infrastructure to include in the network model that: (i) are expected to be in service no later than the first day of the relevant Capacity Commitment Period; and (ii) may have a material impact on the network model, a potential interface constraint, or on one or more Local Sourcing Requirements. The network model shall be used, among other purposes, (i) for the Forward Capacity Market qualification process and (ii) to calculate transmission interface limits in order to forecast the Local Sourcing Requirements. The network model shall include:

(a) For the relevant Capacity Commitment Period, the network model shall include:

(i) all existing resources, along with any associated interconnection facilities and/or Elective Transmission Upgrades that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Sections III.13.2.5.2.5.3 and III.13.2.8.3;

(ii) all new resources with Qualified Capacity for the relevant Capacity Commitment Period, along with any associated interconnection facilities and/or Elective Transmission Upgrades; and

(iii) in the case of an initial interconnection analysis that is conducted consistent with the Network Capability Interconnection Standard, any generating unit or External Elective Transmission Upgrade that has a valid Interconnection Request and is reasonably expected to declare commercial operation no later than the first day of the relevant Capacity Commitment Period.

(b) Prior to each Forward Capacity Auction and each annual reconfiguration auction, the ISO shall determine and publish a list of the transmission projects and elements of transmission projects that will be included in the network model. During the process of making the transmission infrastructure determinations, as described in Section III.12.6.1, the ISO shall consult with the Governance Participants, the Transmission Owners, any transmission project proponents, the state utility regulatory agencies in New England and, as appropriate, other state agencies.

III.12.6.1. Process for Establishing the Network Model.

(a) The ISO shall establish an initial network model prior to the Forward Capacity Auction that only includes transmission infrastructure, including Internal Elective Transmission Upgrades, that is already in service at the time that the initial network model is developed.

(b) After establishing the initial network model, the ISO shall compile a preliminary list of the transmission projects or elements of transmission projects in the RSP Project List, individually or in combination with each other, as appropriate, to identify transmission projects that may achieve an in-service date no later than the first day of the relevant Capacity Commitment Period and that will have a material impact on the network model, on a potential interface constraint or one or more Local Sourcing Requirements.

(c) For the transmission projects or elements of transmission projects in the RSP Project List that are included in the preliminary list developed pursuant to subsection (b), the ISO shall determine whether the transmission projects or elements of transmission projects meet all of the initial threshold milestones specified in Section III.12.6.2 and will be considered for further evaluation pursuant to subsection (d).

(d) For those transmission projects or elements of transmission projects that meet the initial threshold milestones in subsection (c), the ISO shall use the evaluation criteria specified in Section III.12.6.3, and any other relevant information, to determine whether to include a transmission project or element of a transmission project in the final network model.

(e) If after completing its evaluation pursuant to Sections III.12.6.1 through III.12.6.3 and conferring with the transmission project proponents, the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO determines that the transmission project or a portion of the transmission project is reasonably expected to be in service no later than the first day for the relevant Capacity Commitment Period, then such transmission project or portion of transmission project shall be considered in service in the finalized network model to calculate the transmission interface limits pursuant to Section III.12.5.

III.12.6.2. Initial Threshold to be Considered In-Service.

The ISO shall determine whether transmission projects or elements of transmission projects meet all of the following initial threshold milestones:

(a) A critical path schedule for the transmission project has been furnished to ISO showing that the transmission project or the element of the transmission project will be in-service no later than the first day of the relevant Capacity Commitment Period. The critical path schedule must be sufficiently detailed to allow the ISO to evaluate the feasibility of the schedule.

(b) At the time of the milestone review, siting and permitting processes, if required, are on schedule as shown on the critical path schedule.

(c) At the time of the milestone review, engineering is on schedule as shown on the critical path schedule.

(d) At the time of the milestone review, land acquisition, if required, is on schedule as shown on the critical path schedule.

(e) Corporate intent to build the transmission project has been furnished to the ISO. An officer of the host Transmission Owner or Elective Transmission Upgrade Interconnection Customer has submitted to the ISO a statement verifying that the officer has reviewed the proposal and critical path schedule submitted to the ISO, and the Transmission Owner or Elective Transmission Upgrade Interconnection Customer concurs that the schedule is achievable, and it is the intent of the Transmission Owner or Elective Transmission Upgrade Interconnection Customer to build the proposed transmission project in accordance with that schedule. The Transmission Owner or Elective Transmission Upgrade Interconnection Customer may develop alternatives or modifications to the transmission project during the course of design of the transmission project that accomplish at least the same transfer capability. Such alternatives or modifications are acceptable, so long as the ISO determines that the alternative or modification is reasonably expected to achieve an in-service date no later than the first day of the relevant Capacity Commitment Period. The provision of an officer's statement shall be with the understanding that the statement shall not create any liability on the officer and that any liability with respect to the Transmission Owner's obligations shall be as set forth in the Transmission Operating Agreement and shall not be affected by such officer's statement.

III.12.6.3. Evaluation Criteria.

For a transmission project or element of a transmission project that meets the initial threshold milestones specified in Section III.12.6.2, the ISO shall consider the following factors and any other relevant information to determine whether to include the transmission project or element of the transmission project in the network model for the relevant Capacity Commitment Period.

(a) Sufficient engineering to initiate construction is on schedule as shown on the critical path schedule.

(b) Approval under Section I.3.9 of the Transmission, Markets and Services Tariff, if required, has been obtained or is on schedule to be obtained as shown on the critical path schedule.

(c) Significant permits, including local permits, if required to initiate construction have been obtained or are on schedule consistent with the critical path schedule.

(d) Easements, if required, have been obtained or are on schedule consistent with the critical path schedule. Needed land purchases, if required, have been made or are on schedule consistent with the critical path schedule.

(e) Any contracts required to procure or construct a transmission project are in place consistent with the critical path schedule. The ISO's analysis may also take into account whether such contracts contain incentive and/or penalty clauses to encourage third parties to advance the delivery of material services to conform with the critical path schedule.

(f) Physical site work is on schedule consistent with the critical path schedule.

(g) The transmission project is in a designated National Interest Electric Transmission Corridor in accordance with Section 216 of the Federal Power Act, 16 U.S.C. §§ 824p.

III.12.6.4. Transmission Projects Selected Through the Competitive Transmission Process.

For a transmission project selected through the competitive transmission process pursuant to Sections 4.3 and 4Aof Attachment K, such transmission project, or relevant portion thereof, shall be considered in-service on the in-service date provided in the executed Selected Qualified Transmission Project Sponsor Agreement. The ISO shall use the in-service date in the executed Selected Qualified Transmission Project Sponsor Agreement to determine whether to include the transmission project, or relevant portion thereof, in the network model for the relevant Capacity Commitment Period. In the event that the selected transmission project includes an upgrade(s) located on a PTO's existing transmission system where the Selected Qualified Transmission Project Sponsor is not the PTO for the existing system element(s) being upgraded, the process for establishing the in-service date and determining whether to include the upgrade(s) on the existing transmission system, or relevant portion thereof, in the network model for the Capacity Commitment Period shall be as described in Section III.12.6.1.

III.12.7. Resource Modeling Assumptions.

III.12.7.1. Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as additional capacity to determine the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all other resources in the New England Control Area, the reliability, or LOLE, of the New England Control

Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

When modeling transmission constraints for the determination of Local Resource Adequacy Requirements, the same proxy units may be added to the import-constrained zone or elsewhere in the rest of the New England Control Area depending on where system constraints exist.

III.12.7.2. Capacity.

The resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall include:

(a) all Existing Generating Capacity Resources,

(b) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,

(c) all Existing Import Capacity Resources backed by a multiyear contract to provide capacity in the New England Control Area, where that multiyear contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and

(d) Existing Demand Capacity Resources that are qualified to participate in the Forward Capacity Market and New Demand Capacity Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

but shall exclude:

(e) capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

(f) capacity de-listed or retired as a result of Permanent De-List Bids, Retirement De-List Bids, or substitution auction demand bids that cleared in previous Forward Capacity Auctions, and

(g) capacity retired pursuant to Section III.13.1.2.4.1(a), unless the Lead Market Participant has opted to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1.

The rating of Existing Generating Capacity Resources and Existing Import Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be the summer Qualified Capacity value of such resources for the relevant zone. The rating of Demand Capacity Resources shall be the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value. The rating of resources, except for Demand Capacity Resources, cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period shall be based on the amount of Qualified Capacity that cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period. Resources are located within the Capacity Zones in which they are electrically connected as determined during the qualification process.

III.12.7.2.1. [Reserved.]

III.12.7.3. Resource Availability.

The Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated taking resource availability into account and shall be determined as follows:

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

(b) [Reserved.]

For resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that do not have sufficient data to calculate an availability metric as defined in subsection (a) above, class average data for similar resource types shall be used.

For existing Active Demand Capacity Resources:
Historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

III.12.7.4. Load and Capacity Relief.

Load and capacity relief expected from system-wide implementation of the following actions specified in ISO New England Operating Procedure No. 4. Action During a Capacity Deficiency, shall be included in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values:

(a) **Implement voltage reduction**. The MW value of the load relief shall be equal to 1% of (the 90/10 forecasted seasonal net peak loads minus all Existing Demand Capacity Resources).

(b) **Arrange for available Emergency energy from Market Participants or neighboring Control Areas.** These actions are included in the calculation through the use of tie benefits to meet system needs. The MW value of tie benefits is calculated in accordance with Section III.12.9.

(c) **Maintain an adequate amount of ten-minute synchronized reserves**. The amount of system reserves included in the determination of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be consistent with those needed for reliable system operations during Emergency Conditions. When modeling transmission constraints, the reserve requirement for a zone shall be the zone’s pro rata share of the forecasted system peak load multiplied by the system reserves needed for reliable system operations during Emergency Conditions.

III.12.8. Load Modeling Assumptions.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias. To ensure that Demand Response Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources are not reflected as reductions in the load forecast, ~~Demand Capacity Resources~~ the ISO shall ~~be~~ reflect~~ed~~ them in ~~the~~ historical loads ~~forecast~~ as specified below.~~:~~

(a) The ISO shall add back into historical loads the metered MW demand reduction of Demand Response Resources dispatched by the ISO. ~~Expected reductions from an installed or forecast Demand Capacity Resource not qualifying for or not participating in the Forward Capacity Auction shall be reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period. The expected reduction from these resources will be included in the load forecast to the extent that they meet the qualification process rules, including monitoring and verification plan and financial assurance requirements. If no qualification process rules are in place for the expected reductions from these resources, they shall not be included within the load forecast.~~

(b) [Reserved.]~~Expected reductions from an installed or forecast Demand Capacity Resource that qualifies to participate in the Forward Capacity Market, participates but does not clear in the Forward Capacity Auction, or has cleared in a previous Forward Capacity Auction and is expected to continue in the Forward Capacity Market shall not be reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period.~~

(c) [Reserved.]

(d) The ISO shall add back into historical loads summer and winter MW values to account for On-Peak Demand Resources and Seasonal Peak Demand Resources as follows:

The ISO shall develop a trend line between (i) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (June 1, 2006) and (ii) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for June 1 of the associated Capacity Commitment Period. To determine the summer

MW values to be added back into historical loads, the ISO shall apply the resulting trend to the summer months (April through November) in all the historical years covered by the trend line.

The ISO shall develop a trend line between (i) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (December 1, 2006) and (ii) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for December 1 of the associated Capacity Commitment Period. To determine the winter MW values to be added back into historical loads, the ISO shall apply the resulting trend to the winter months (December through March) in all the historical years covered by the trend line.

The ISO shall make adjustments to forecasted loads to account for any differences between the most recently available MW values reflective of the Capacity Supply Obligations that On-Peak Demand Resources and Seasonal Peak Demand Resources acquired in each of the annual reconfiguration auctions and the MW values reflective of the Capacity Supply Obligations that those resources acquired in the corresponding Forward Capacity Auctions.~~Any realized Demand Capacity Resource reductions in the historical period that received Forward Capacity Market payments for these reductions, or Demand Capacity Resource reductions that are expected to receive Forward Capacity Market payments by participating in the upcoming Forward Capacity Auction or having cleared in a previous Forward Capacity Auction, shall be added back into the appropriate historical loads to ensure that such resources are not reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period.~~

III.12.9. Tie Benefits.

The Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated assuming appropriate tie benefits, if any, available from interconnections with neighboring Control Areas. Tie benefits shall be calculated only for interconnections (1) without Capacity Network Import Interconnection Service or Network Import Interconnection Service or (2) that have not requested Capacity Network Import Interconnection Service or Network Import Interconnection Service with directly interconnected neighboring Control Areas with which the ISO has in effect agreements providing for emergency support to New England, including but not limited to inter-Control Area coordination agreements, emergency aid agreements and the NPCC Regional Reliability Plan.

Tie benefits shall be calculated using a probabilistic multi-area reliability model, by comparing the LOLE for the New England system before and after interconnecting the system to the neighboring Control Areas. To quantify tie benefits, firm capacity equivalents shall be added until the LOLE of the isolated New England Control Area is equal to the LOLE of the interconnected New England Control Area.

III.12.9.1. Overview of Tie Benefits Calculation Procedure.

III.12.9.1.1. Tie Benefits Calculation for the Forward Capacity Auction and Annual Reconfiguration Auctions; Modeling Assumptions and Simulation Program.

For each Capacity Commitment Period, tie benefits shall be calculated for the Forward Capacity Auction and the third annual reconfiguration auction using the calculation methodology in this Section III.12.9. For the first and second annual reconfiguration auctions for a Capacity Commitment Period, the tie benefits calculated for the associated Forward Capacity Auction shall be utilized in determining the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values as adjusted to account for any changes in import capability of interconnections with neighboring Control Areas and changes in import capacity resources using the methodologies in Section III.12.9.6.

Tie benefits shall be calculated using the modeling assumptions developed in accordance with Section III.12.9.2 and using the General Electric Multi-area Reliability Simulation (MARS) program.

III.12.9.1.2. Tie Benefits Calculation.

The total tie benefits to New England from all directly interconnected neighboring Control Areas are calculated first using the methodology in Section III.12.9.3. Following the calculation of total tie benefits, individual tie benefits from each qualifying neighboring Control Area are calculated using the methodology in Section III.12.9.4.1. If the sum of the tie benefits from each Control Area does not equal the total tie benefits to New England, then each Control Area's tie benefits are adjusted based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits calculated for each Control Area using the methodology in Section III.12.9.4.2. Following this calculation, tie benefits are calculated for each qualifying individual interconnection or group of interconnections using the methodology in Section III.12.9.5.1. If the sum of the tie benefits from individual interconnections or groups of interconnections does not equal their associated Control Area's tie benefits, then the tie benefits of each individual interconnection or group of interconnections is adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits within the Control Area using the methodology in Section III.12.9.5.2.

III.12.9.1.3. Adjustments to Account for Transmission Import Capability and Capacity Imports.

Once the initial calculation of tie benefits is performed, the tie benefits for each individual interconnection or group of interconnections is adjusted to account for capacity imports and any changes in the import capability of interconnections with neighboring Control Areas, using the methodologies in Section III.12.9.6. Once the import capability and capacity import adjustments are completed, the sum of the tie benefits of all individual interconnections and groups of interconnections for a Control Area, with the import capability and capacity import adjustments, represents the tie benefits associated with that Control Area, and the sum of the tie benefits from all Control Areas, with the import capability and capacity import adjustments, represents the total tie benefits available to New England.

III.12.9.2. Modeling Assumptions and Procedures for the Tie Benefits Calculation.

III.12.9.2.1. Assumptions Regarding System Conditions.

In calculating tie benefits, "at criterion" system conditions shall be used to model the New England Control Area and all interconnected Control Areas.

III.12.9.2.2. Modeling Internal Transmission Constraints in New England.

In calculating tie benefits, all New England internal transmission constraints that (i) are modeled in the most recent Regional System Plan resource adequacy studies and assessments and (ii) are not addressed by either a Local Sourcing Requirement or a Maximum Capacity Limit calculation shall be modeled, using the procedures in Section III.12.9.2.5.

III.12.9.2.3. Modeling Transmission Constraints in Neighboring Control Areas.

The ISO will review annually NPCC's assumptions regarding transmission constraints in all directly interconnected neighboring Control Areas that are modeled for the tie benefits calculations. In the event that NPCC models a transmission constraint in one of the modeled neighboring Control Areas, the ISO will perform an evaluation to determine which interfaces are most critical to the ability of the neighboring Control Area to reliably provide tie benefits to New England from both operational and planning perspectives, and will model those transmission constraints in the tie benefits calculation, using the procedures in Section III.12.9.2.5.

III.12.9.2.4. Other Modeling Assumptions.

A. External transfer capability determinations. The transfer capability of all external interconnections with New England will be determined using studies that take account of the load, resource and other electrical system conditions that are consistent with those expected during the Capacity Commitment Period for which the calculation is being performed. Transfer capability studies will be performed using simulations that consider the contingencies enumerated in sub-section (iii) below.

(i) The transmission system will be modeled using the following conditions:

1. The forecast 90/10 peak load conditions for the Capacity Commitment Period;
2. Qualified Existing Generating Capacity Resources reflecting their output at their Capacity Network Resource level;
3. Qualified Existing Demand Capacity Resources reflecting their Capacity Supply Obligation received in the most recent Forward Capacity Auction;
4. Transfers on the transmission system that impact the transfer capability of the interconnection under study.

(ii) The system will be modeled in a manner that reflects the design of the interconnection. If an interconnection and its supporting system upgrades were designed to provide incremental capacity into the New England Control Area, simulations will assume imports up to the level that the interconnection was designed to support. If the interconnection was not designed to be so comparably integrated, simulations will determine the amount of power that can be delivered into New England over the interconnection.

(iii) The simulations will take into account contingencies that address a fault on a generator or transmission facility, loss of an element without a fault, and circuit breaker failure following the loss of an element or an association with the operation of a special protection system.

B. In calculating tie benefits, New England capacity exports are removed from the internal capacity resources and are modeled as a resource in the receiving Control Area. The transfer capability of external interconnections is not adjusted to account for capacity exports.

III.12.9.2.5. Procedures for Adding or Removing Capacity from Control Areas to Meet the 0.1 Days Per Year LOLE Standard.

In calculating tie benefits, capacity shall be added or removed from the interconnected system of New England and its neighboring Control Areas, until the LOLE of New England and the LOLE of each Control Area of the interconnected system equals 0.1 days per year simultaneously. The following procedures shall be used to add or remove capacity within New England and the interconnected Control Areas to achieve that goal.

A. **Adding Proxy Units within New England when the New England system is short of capacity**. In modeling New England as part of the interconnected system, if New England is short of capacity to meet the 0.1 days per year LOLE, proxy units (with the characteristics identified in Section III.12.7.1) will be added to the sub-areas that are created by any modeled internal transmission constraints within New England, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the New England Control Area, then proxy units will be added to the entire Control Area. If, as a result of the addition of one or more proxy units, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(b) will be used to remove the surplus capacity.

B. **Removing capacity from New England when the New England system is surplus of capacity.** In modeling New England as part of the interconnected system, if New England is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in these surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the existing Qualified Capacity, and any amount of proxy units added in that sub-area that is above its 50-50 peak load forecast. Notwithstanding the foregoing, if removing resources will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratios described above for the removal of capacity surplus. If there are no modeled internal transmission constraints in the New England Control Area, then the surplus capacity shall be removed from the entire Control Area.

C. **Adding capacity within neighboring Control Areas when the neighboring Control Area is short of capacity**. In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is short of capacity to meet the 0.1 days per year LOLE, additional capacity will be added to the neighboring Control Area's sub-areas that are created by any modeled internal transmissions constraints, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the Control Area, then capacity will be added to the entire Control Area. The process that the neighboring Control Area utilizes in its resource adequacy study to meet its resource adequacy criterion will be utilized to add capacity to that Control Area. In filing the Installed Capacity Requirement values pursuant to Section III.12.3, the ISO will provide citations to any resource adequacy studies relied upon for these purposes. If, as a result of the capacity addition, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(d) shall be used to remove the surplus capacity.

D. **Removing capacity from neighboring Control Areas when the neighboring Control Area is surplus of capacity**. In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the neighboring Control Area's sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in the surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the installed capacity in the sub-area above its 50/50 peak load forecast. For a sub-area that has a minimum locational resource requirement above its 50/50 peak load forecast, the amount of capacity surplus is the amount of the installed capacity in the sub-area above its minimum locational resource requirement. Notwithstanding the foregoing, if removing resources from a sub-area will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratio of capacity surplus in the sub-area to the total capacity surplus in the those remaining surplus sub-areas. If there are no modeled internal transmission constraints in the neighboring Control Area, then the surplus capacity will be removed from the entire Control Area.

E. **Maintaining the neighboring Control Area's locational resource requirements**. In modeling a neighboring Control Area with internal transmission constraints, all minimum locational resource requirements in the Control Area's sub-areas as established by the neighboring Control Area's installed capacity requirement calculations shall be observed.

III.12.9.3. Calculating Total Tie Benefits.

The total tie benefits with all qualifying directly interconnected neighboring Control Areas shall be calculated by comparing the interconnection state of the New England system with all interconnections to neighboring Control Areas connected with the interconnection state of the New England system with all interconnections with neighboring Control Areas disconnected. To calculate total tie benefits:

- **A.** The New England system shall be interconnected with all directly interconnected neighboring Control Areas and the New England Control Area, and each neighboring Control Area shall be brought to 0.1 days per year LOLE simultaneously by adjusting the capacity of each Control Area, utilizing the methods for adding or removing capacity in Section III.12.9.2.5.
- **B.** Once the interconnected system is brought to 0.1 days per year LOLE, the LOLE of the New England Control Area shall be calculated a second time, with the New England system isolated from the rest of the interconnected system that was brought to 0.1 days per year LOLE.
- **C.** Total tie benefits shall be the sum of the amounts of firm capacity that needs to be added to the isolated New England Control Area at the point at which each interconnection with neighboring Control Areas interconnects in New England to bring the New England LOLE back to 0.1 days per year. This value is subject to adjustment in accordance with Section III.12.9.6.

III.12.9.4. Calculating Each Control Area's Tie Benefits.

III.12.9.4.1. Initial Calculation of a Control Area's Tie Benefits.

Tie benefits from each neighboring Control Area shall be determined by calculating the tie benefits for every possible interconnection state that has an impact on the tie benefit value between the New England system and the target neighboring Control Area. If two or more interconnections between New England and the target neighboring Control Area exist, then all interconnections grouped together will be used to represent the state of interconnection between New England and the target neighboring Control Area. The tie benefits from the target neighboring Control Area shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.4.2.

III.12.9.4.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual Control Area tie benefits calculated in accordance with Section III.12.9.4.1 is different than the total tie benefits from all Control Areas calculated in accordance with Section III.12.9.3, then each Control Area's tie benefits shall be increased or decreased based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits for each individual Control Area, so that the sum of each Control Area's tie benefits, after the pro-ration, is equal to the total tie benefits calculated in accordance with Section III.12.9.3. The pro-rated Control Area tie benefits are subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.5. Calculating Tie Benefits for Individual Ties.

Tie benefits shall be calculated for an individual interconnection or group of interconnections to the extent that a discrete and material transfer capability can be identified for the interconnection or group of interconnections. All interconnections or groups of interconnections shall have equal rights in calculating individual tie benefits, with no grandfathering or incremental tie capability treatment.

For purposes of calculating tie benefits, a group of interconnections refers to two or more AC lines that operate in parallel to form a transmission interface in which there are significant overlapping contributions of each line toward establishing the transfer limit, such that the individual lines in a group of interconnections cannot be assigned individual contributions.

III.12.9.5.1. Initial Calculation of Tie Benefits for an Individual Interconnection or Group of Interconnections.

Tie benefits for an individual interconnection or group of interconnections shall be calculated by calculating tie benefits for each possible interconnection state between the New England system and the individual interconnection or group of interconnections. The tie benefits from that interconnection or group of interconnections shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.5.2.

III.12.9.5.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual interconnection's or group of interconnection's tie benefits calculated in accordance with Section III.12.9.5.1 is different than the associated Control Area's tie benefits calculated in accordance with Section III.12.9.4, then the tie benefits of the individual interconnection or group of interconnections shall be adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits for each interconnection or group of interconnections in that Control Area, so that the sum of the tie benefits for each interconnection or group of interconnections in the Control Area, after the pro-ration, is equal to the total tie benefits for the Control Area calculated in accordance with Section III.12.9.4. The pro-rated tie benefits for each interconnection or group of interconnections is subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.6. Accounting for Capacity Imports and Changes in External Transmission Facility Import Capability.

III.12.9.6.1. Accounting for Capacity Imports.

In the initial tie benefits calculations, capacity imports are modeled as internal resources in New England, and the import capability of the interconnections with neighboring Control Areas is not reduced to reflect the impact of capacity imports. After the initial tie benefits calculations, total tie benefits, tie benefits for each Control Area, and tie benefits from each individual interconnection or group of interconnections shall be adjusted to account for capacity imports using the methodology contained in this Section III.12.9.6.1. For the Forward Capacity Auction and third annual reconfiguration auction, this adjustment shall be applied to the tie benefit values calculated in accordance with Sections III.12.9.3, III.12.9.4 and III.12.9.5 respectively. For the first and second annual reconfiguration auctions, this adjustment shall be applied to the tie benefits values calculated for the Forward Capacity Auction.

A. Capacity imports shall be deducted from the import capability of each individual interconnection or group of interconnections to determine the available import capability of the interconnection or group of interconnections prior to accounting for tie benefits from those interconnections. The transfer capability of an interconnection or group of interconnections shall be determined using the procedures in Section III.12.9.2.4.A.

B. If the tie benefits value of an individual interconnection or group of interconnections, as determined in accordance with Section III.12.9.5, is greater than the remaining transmission import capability of the interconnection or group of interconnections after accounting for capacity imports, the tie benefit value of the individual interconnection or group of interconnections shall be equal to the remaining transmission import capability (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2). If the tie benefits value of an individual interconnection or group of interconnections is not greater than the remaining transmission import capability after accounting for capacity imports, then the tie benefit value of the individual interconnection or group of interconnections shall be equal to the value determined in accordance with Section III.12.9.5 (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2).

C. The tie benefits for each Control Area shall be the sum of the tie benefits from the individual interconnections or groups of interconnections with that Control Area, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.

D. The total tie benefits from all qualifying neighboring Control Areas shall be the sum of the Control Area tie benefits, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.

E. For purposes of determining the adjustment to tie benefits to account for capacity imports under this Section III.12.9.6.1, the capacity imports applicable for determining tie benefits for the Forward Capacity Auction shall be the Qualified Existing Import Capacity Resources for the relevant Capacity Commitment Period, and the capacity imports applicable for determining tie benefits for the annual reconfiguration auctions are those Import Capacity Resources that hold Capacity Supply Obligations for the relevant Capacity Commitment Period as of the time the tie benefits calculation is being performed for the annual reconfiguration auction.

III.12.9.6.2. Changes in the Import Capability of Interconnections with Neighboring Control Areas.

For purposes of calculating tie benefits for the Forward Capacity Auction and third annual reconfiguration auction, the most recent import capability values for an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the modeling of system conditions for the tie benefits calculation. In addition, for the first and second annual reconfiguration auctions, any changes to the import capability of an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the adjustment to tie benefits to account for capacity imports under Section III.12.9.6.1.

III.12.9.7. Tie Benefits Over the HQ Phase I/II HVDC-TF.

The tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1 shall be allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.

III.12.10. Calculating the Maximum Amount of Import Capacity Resources that May be Cleared Over External Interfaces in the Forward Capacity Auction and Reconfiguration Auctions.

For external interfaces, Import Capacity Resources shall be allowed in the Forward Capacity Auction and reconfiguration auctions up to the interface limit minus the tie benefits, calculated pursuant to Section III.12.9.1 or 12.9.2 over the applicable interface.

III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

Prior to each Forward Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction in accordance with this Section III.12.1.

The ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period. The Installed Capacity Requirement shall be determined assuming all resources pursuant to Sections III.12.7 and III.12.9 will be deliverable to meet the forecasted demand determined pursuant to Section III.12.8.

If the Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Installed Capacity Requirement. The modeling assumptions used in determining the Installed Capacity Requirement are specified in Sections III.12.7, III.12.8 and III.12.9. For the purpose of this Section III.12, a "resource" shall include generating resources, demand resources, and import capacity resources eligible to receive capacity payments in the Forward Capacity Market.

III.12.1.1. System-Wide Marginal Reliability Impact Values.

Prior to each Forward Capacity Auction, the ISO shall determine the system-wide Marginal Reliability Impact of incremental capacity at various capacity levels for the New England Control Area. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used in determining the Installed Capacity Requirement.

III.12.2. Local Sourcing Requirements and Maximum Capacity Limits.

Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section

III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction.

The ISO shall use consistent assumptions and standards to establish a resource's electrical location for purposes of qualifying a resource for the Forward Capacity Market and for purposes of calculating Local Sourcing Requirements and Maximum Capacity Limits. The methodology used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.2.1 and III.12.2.2, respectively. The modeling assumptions used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.5, III.12.6, III.12.7, III.12.8 and III.12.9.

III.12.2.1. Calculation of Local Sourcing Requirements for Import-Constrained Capacity Zones.

For each import-constrained Capacity Zone, the Local Sourcing Requirement shall be the amount needed to satisfy the higher of: (i) the Local Resource Adequacy Requirement as determined pursuant to Section III.12.2.1.1; or (ii) the Transmission Security Analysis Requirement as determined pursuant to Section III.12.2.1.2.

III.12.2.1.1. Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

(a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the import-constrained side of the interface, if any; and (ii) the rest of the New England Control Area which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits on the unconstrained side of the interface, if any.

(b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Local Resource Adequacy Requirement for the import-constrained Capacity Zone Z shall be determined in accordance with the following formula:

LRA_Z	=	$Resources_z$ +Proxy $Units_z$ – (Proxy Units $Adjustment_z$(1-FOR_z))-(Firm Load $Adjustment_z$(1-FOR_z))

In which:

LRA_Z	=	MW of Local Resource Adequacy Requirement for Capacity Zone Z;
$Resources_z$	=	MW of resources electrically located within Capacity Zone Z, including import Capacity Resources on the import-constrained side of the interface, if any;
Proxy $Units_z$	=	MW of proxy unit additions in Load Zone Z;
Firm Load $Adjustment_z$	=	MW of firm load added (or subtracted) within Capacity Zone Z to make the LOLE of the New England Control Area equal to 0.105 days per year; and
FOR_z	=	Capacity weighted average of the forced outage rate modeled for all resources within Capacity Zone Z, including and proxy unit additions to Capacity Zone Z.
Proxy Units Adjustment	=	MW of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1

days/year.

To determine the Local Resource Adequacy Requirement, the firm load is adjusted within Capacity Zone Z until the LOLE of the New England Control Area reaches 0.105 days per year. The LOLE of 0.105 days per year includes an allowance for transmission related LOLE of 0.005 days per year associated with each interface. As firm load is added to (or subtracted from) Capacity Zone Z, an equal amount of firm load is removed from (or added to) the rest of New England Control Area.

III.12.2.1.2. Transmission Security Analysis Requirement.
A Transmission Security Analysis shall be used to determine the requirement of the zone being studied, and shall include the following features:

(a) The ISO shall perform a series of transmission load flow studies and/or a deterministic operable capacity analysis targeted at determining the performance of the system under stressed conditions, and at developing a resource requirement sufficient to allow the system to operate through those stressed conditions.

(b) The Transmission Security Analysis Requirement shall be set at a level sufficient to cover most reasonably anticipated events, but will not guarantee that every combination of obligated resources within the zone will meet system needs.

(c) In performing the Transmission Security Analysis, the ISO may establish static transmission interface transfer limits, as identified pursuant to Section III.12.5, as a reasonable representation of the transmission system's capability to serve load with available existing resources.

(d) The Transmission Security Analysis may model the entire New England system and individual zones, for both the first contingency (N-1) and second contingency (N-1-1) conditions. First contingency conditions (N-1) shall include the loss of the most critical generator or most critical transmission element with respect to the zone. Second contingency conditions (N-1-1) shall include both: (i) the loss of the most critical generator with respect to the zone followed by the loss of the most critical transmission element ("Line-Gen"); and (ii) the loss of the most critical transmission element followed by the loss of the next most critical transmission element ("Line-Line") with respect to the zone.

III.12.2.1.3. Marginal Reliability Impact Values for Import-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each import-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) shall be reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero.

III.12.2.2. Calculation of Maximum Capacity Limit for Export-Constrained Capacity Zones.

For each export-constrained Capacity Zone, the Maximum Capacity Limit shall be calculated using the following method:

(a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the export-constrained side of the interface, if any; and (ii) the rest of the New England Control Area, which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits to the rest of the New England Control Area, if any.

(b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Maximum Capacity Limit for the export-constrained Capacity Zone Y shall be determined in accordance with the following formula:

$$\text{Maximum Capacity Limit}_Y = ICR - LRA_{RestofNewEngland}$$

In which:

Maximum Capacity Limit$_Y$ = Maximum MW amount of resources , including Import Capacity Resources on the export-constrained side of the interface, if any, that can be procured in the export-constrained Capacity Zone Y to meet the Installed Capacity Requirement;

ICR = MW of Installed Capacity Requirement for the New England Control Area, determined in accordance with Section III.12.1; and

$LRA_{RestofNewEngland}$ = MW of Local Sourcing Requirement for the rest of the New England Control Area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Section III.12.2.1.

III.12.2.2.1. Marginal Reliability Impact Values for Export-Constrained Capacity Zones.
Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each export-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit.

III.12.3 Consultation and Filing of Capacity Requirements.
At least two months prior to filing the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves with the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves

for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act 90 days prior to the Forward Capacity Auction for the Capacity Commitment Period. The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given FCA, any new Capacity Zone must have received approval from the Commission prior to the Existing Capacity Qualification Deadline of the applicable FCA.

III.12.4. Capacity Zones.

For each Forward Capacity Auction, the ISO shall, using the results of the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K, determine the Capacity Zones to model as described below, and will include such designations in its filing with the Commission pursuant to Section III.13.8.1(c):

(a) The ISO shall model in the Forward Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit is less than the sum of the existing Qualified Capacity and proposed new capacity that could qualify to be procured in the export constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface.

(b) The ISO shall model in the Forward Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the second contingency transmission capability results in a line-line Transmission Security Analysis Requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, that is greater than the existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model out-of-service all Retirement De-List Bids and Permanent De-List Bids (including any received for the current Forward Capacity Auction at the time of this calculation), substitution auction demand bids submitted for the current Forward Capacity Auction, rejected for reliability Static De-List Bids from the most recent previous Forward Capacity Auction, and rejected for reliability Dynamic De-List Bids from the most recent previous Forward Capacity Auction.

(c) Adjacent Load Zones that are neither export-constrained nor import-constrained shall be modeled together as the Rest of Pool Capacity Zone in the Forward Capacity Auction.

III.12.4A. Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location of Active Demand Capacity Resources. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction, and those Dispatch Zones shall remain in place through the end of the Capacity Commitment Period for which they were established. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.12.5. Transmission Interface Limits.

Transmission interface limits, used in the determination of Local Sourcing Requirements, shall be determined pursuant to ISO Tariff Section II, Attachment K using network models that include all resources, existing transmission lines and proposed transmission lines that the ISO determines, in accordance with Section III.12.6, will be in service no later than the first day of the relevant Capacity Commitment Period. The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

III.12.6. Modeling Assumptions for Determining the Network Model.

The ISO shall determine, in accordance with this Section III.12.6, the generating units and transmission infrastructure to include in the network model that: (i) are expected to be in service no later than the first day of the relevant Capacity Commitment Period; and (ii) may have a material impact on the network model, a potential interface constraint, or on one or more Local Sourcing Requirements. The network model shall be used, among other purposes, (i) for the Forward Capacity Market qualification process and (ii) to calculate transmission interface limits in order to forecast the Local Sourcing Requirements. The network model shall include:

(a) For the relevant Capacity Commitment Period, the network model shall include:

(i) all existing resources, along with any associated interconnection facilities and/or Elective Transmission Upgrades that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Sections III.13.2.5.2.5.3 and III.13.2.8.3;

(ii) all new resources with Qualified Capacity for the relevant Capacity Commitment Period, along with any associated interconnection facilities and/or Elective Transmission Upgrades; and

(iii) in the case of an initial interconnection analysis that is conducted consistent with the Network Capability Interconnection Standard, any generating unit or External Elective Transmission Upgrade that has a valid Interconnection Request and is reasonably expected to declare commercial operation no later than the first day of the relevant Capacity Commitment Period.

(b) Prior to each Forward Capacity Auction and each annual reconfiguration auction, the ISO shall determine and publish a list of the transmission projects and elements of transmission projects that will be included in the network model. During the process of making the transmission infrastructure determinations, as described in Section III.12.6.1, the ISO shall consult with the Governance Participants, the Transmission Owners, any transmission project proponents, the state utility regulatory agencies in New England and, as appropriate, other state agencies.

III.12.6.1. Process for Establishing the Network Model.

(a) The ISO shall establish an initial network model prior to the Forward Capacity Auction that only includes transmission infrastructure, including Internal Elective Transmission Upgrades, that is already in service at the time that the initial network model is developed.

(b) After establishing the initial network model, the ISO shall compile a preliminary list of the transmission projects or elements of transmission projects in the RSP Project List, individually or in combination with each other, as appropriate, to identify transmission projects that may achieve an in-service date no later than the first day of the relevant Capacity Commitment Period and that will have a material impact on the network model, on a potential interface constraint or one or more Local Sourcing Requirements.

(c) For the transmission projects or elements of transmission projects in the RSP Project List that are included in the preliminary list developed pursuant to subsection (b), the ISO shall determine whether the transmission projects or elements of transmission projects meet all of the initial threshold milestones specified in Section III.12.6.2 and will be considered for further evaluation pursuant to subsection (d).

(d) For those transmission projects or elements of transmission projects that meet the initial threshold milestones in subsection (c), the ISO shall use the evaluation criteria specified in Section III.12.6.3, and any other relevant information, to determine whether to include a transmission project or element of a transmission project in the final network model.

(e) If after completing its evaluation pursuant to Sections III.12.6.1 through III.12.6.3 and conferring with the transmission project proponents, the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO determines that the transmission project or a portion of the transmission project is reasonably expected to be in service no later than the first day for the relevant Capacity Commitment Period, then such transmission project or portion of transmission project shall be considered in service in the finalized network model to calculate the transmission interface limits pursuant to Section III.12.5.

III.12.6.2. Initial Threshold to be Considered In-Service.

The ISO shall determine whether transmission projects or elements of transmission projects meet all of the following initial threshold milestones:

(a) A critical path schedule for the transmission project has been furnished to ISO showing that the transmission project or the element of the transmission project will be in-service no later than the first day of the relevant Capacity Commitment Period. The critical path schedule must be sufficiently detailed to allow the ISO to evaluate the feasibility of the schedule.

(b) At the time of the milestone review, siting and permitting processes, if required, are on schedule as shown on the critical path schedule.

(c) At the time of the milestone review, engineering is on schedule as shown on the critical path schedule.

(d) At the time of the milestone review, land acquisition, if required, is on schedule as shown on the critical path schedule.

(e) Corporate intent to build the transmission project has been furnished to the ISO. An officer of the host Transmission Owner or Elective Transmission Upgrade Interconnection Customer has submitted to the ISO a statement verifying that the officer has reviewed the proposal and critical path schedule submitted to the ISO, and the Transmission Owner or Elective Transmission Upgrade Interconnection Customer concurs that the schedule is achievable, and it is the intent of the Transmission Owner or Elective Transmission Upgrade Interconnection Customer to build the proposed transmission project in accordance with that schedule. The Transmission Owner or Elective Transmission Upgrade Interconnection Customer may develop alternatives or modifications to the transmission project during the course of design of the transmission project that accomplish at least the same transfer capability. Such alternatives or modifications are acceptable, so long as the ISO determines that the alternative or modification is reasonably expected to achieve an in-service date no later than the first day of the relevant Capacity Commitment Period. The provision of an officer's statement shall be with the understanding that the statement shall not create any liability on the officer and that any liability with respect to the Transmission Owner's obligations shall be as set forth in the Transmission Operating Agreement and shall not be affected by such officer's statement.

III.12.6.3. Evaluation Criteria.

For a transmission project or element of a transmission project that meets the initial threshold milestones specified in Section III.12.6.2, the ISO shall consider the following factors and any other relevant information to determine whether to include the transmission project or element of the transmission project in the network model for the relevant Capacity Commitment Period.

(a) Sufficient engineering to initiate construction is on schedule as shown on the critical path schedule.

(b) Approval under Section I.3.9 of the Transmission, Markets and Services Tariff, if required, has been obtained or is on schedule to be obtained as shown on the critical path schedule.

(c) Significant permits, including local permits, if required to initiate construction have been obtained or are on schedule consistent with the critical path schedule.

(d) Easements, if required, have been obtained or are on schedule consistent with the critical path schedule. Needed land purchases, if required, have been made or are on schedule consistent with the critical path schedule.

(e) Any contracts required to procure or construct a transmission project are in place consistent with the critical path schedule. The ISO's analysis may also take into account whether such contracts contain incentive and/or penalty clauses to encourage third parties to advance the delivery of material services to conform with the critical path schedule.

(f) Physical site work is on schedule consistent with the critical path schedule.

(g) The transmission project is in a designated National Interest Electric Transmission Corridor in accordance with Section 216 of the Federal Power Act, 16 U.S.C. §§ 824p.

III.12.6.4. Transmission Projects Selected Through the Competitive Transmission Process.

For a transmission project selected through the competitive transmission process pursuant to Sections 4.3 and 4Aof Attachment K, such transmission project, or relevant portion thereof, shall be considered in-service on the in-service date provided in the executed Selected Qualified Transmission Project Sponsor Agreement. The ISO shall use the in-service date in the executed Selected Qualified Transmission Project Sponsor Agreement to determine whether to include the transmission project, or relevant portion thereof, in the network model for the relevant Capacity Commitment Period. In the event that the selected transmission project includes an upgrade(s) located on a PTO's existing transmission system where the Selected Qualified Transmission Project Sponsor is not the PTO for the existing system element(s) being upgraded, the process for establishing the in-service date and determining whether to include the upgrade(s) on the existing transmission system, or relevant portion thereof, in the network model for the Capacity Commitment Period shall be as described in Section III.12.6.1.

III.12.7. Resource Modeling Assumptions.

III.12.7.1. Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as additional capacity to determine the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all other resources in the New England Control Area, the reliability, or LOLE, of the New England Control

Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

When modeling transmission constraints for the determination of Local Resource Adequacy Requirements, the same proxy units may be added to the import-constrained zone or elsewhere in the rest of the New England Control Area depending on where system constraints exist.

III.12.7.2. Capacity.

The resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall include:

(a) all Existing Generating Capacity Resources,

(b) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,

(c) all Existing Import Capacity Resources backed by a multiyear contract to provide capacity in the New England Control Area, where that multiyear contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and

(d) Existing Demand Capacity Resources that are qualified to participate in the Forward Capacity Market and New Demand Capacity Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

but shall exclude:

(e) capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

(f) capacity de-listed or retired as a result of Permanent De-List Bids, Retirement De-List Bids, or substitution auction demand bids that cleared in previous Forward Capacity Auctions, and

(g) capacity retired pursuant to Section III.13.1.2.4.1(a), unless the Lead Market Participant has opted to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1.

The rating of Existing Generating Capacity Resources and Existing Import Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be the summer Qualified Capacity value of such resources for the relevant zone. The rating of Demand Capacity Resources shall be the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value. The rating of resources, except for Demand Capacity Resources, cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period shall be based on the amount of Qualified Capacity that cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period. Resources are located within the Capacity Zones in which they are electrically connected as determined during the qualification process.

III.12.7.2.1. [Reserved.]

III.12.7.3. Resource Availability.

The Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated taking resource availability into account and shall be determined as follows:

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

(b) [Reserved.]

For resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that do not have sufficient data to calculate an availability metric as defined in subsection (a) above, class average data for similar resource types shall be used.

For existing Active Demand Capacity Resources:
Historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

III.12.7.4. Load and Capacity Relief.

Load and capacity relief expected from system-wide implementation of the following actions specified in ISO New England Operating Procedure No. 4. Action During a Capacity Deficiency, shall be included in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values:

(a) **Implement voltage reduction**. The MW value of the load relief shall be equal to 1% of (the 90/10 forecasted seasonal net peak loads minus all Existing Demand Capacity Resources).

(b) **Arrange for available Emergency energy from Market Participants or neighboring Control Areas.** These actions are included in the calculation through the use of tie benefits to meet system needs. The MW value of tie benefits is calculated in accordance with Section III.12.9.

(c) **Maintain an adequate amount of ten-minute synchronized reserves**. The amount of system reserves included in the determination of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be consistent with those needed for reliable system operations during Emergency Conditions. When modeling transmission constraints, the reserve requirement for a zone shall be the zone's pro rata share of the forecasted system peak load multiplied by the system reserves needed for reliable system operations during Emergency Conditions.

III.12.8. Load Modeling Assumptions.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias. To ensure that Demand Response Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources are not reflected as reductions in the load forecast, the ISO shall reflect them in historical loads as specified below.

(a) The ISO shall add back into historical loads the metered MW demand reduction of Demand Response Resources dispatched by the ISO.

(b) [Reserved.]

(c) [Reserved.]

(d) The ISO shall add back into historical loads summer and winter MW values to account for On-Peak Demand Resources and Seasonal Peak Demand Resources as follows:

The ISO shall develop a trend line between (i) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (June 1, 2006) and (ii) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for June 1 of the associated Capacity Commitment Period. To determine the summer MW values to be added back into historical loads, the ISO shall apply the resulting trend to the summer months (April through November) in all the historical years covered by the trend line.

The ISO shall develop a trend line between (i) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (December 1, 2006) and (ii) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for December 1 of the associated Capacity Commitment Period. To determine the winter MW values to be added back into historical loads, the ISO shall apply the resulting trend to the winter months (December through March) in all the historical years covered by the trend line.

The ISO shall make adjustments to forecasted loads to account for any differences between the most recently available MW values reflective of the Capacity Supply Obligations that On-Peak Demand Resources and Seasonal Peak Demand Resources acquired in each of the annual reconfiguration auctions and the MW values reflective of the Capacity Supply Obligations that those resources acquired in the corresponding Forward Capacity Auctions.

III.12.9. Tie Benefits.

The Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated assuming appropriate tie benefits, if any, available from interconnections with neighboring Control Areas. Tie benefits shall be calculated only for interconnections (1) without Capacity Network Import Interconnection Service or Network Import Interconnection Service or (2) that have not requested Capacity Network Import Interconnection Service or Network Import Interconnection Service with directly interconnected neighboring Control Areas with which the ISO has in effect agreements providing for emergency support to New England, including but not limited to inter-Control Area coordination agreements, emergency aid agreements and the NPCC Regional Reliability Plan.

Tie benefits shall be calculated using a probabilistic multi-area reliability model, by comparing the LOLE for the New England system before and after interconnecting the system to the neighboring Control Areas. To quantify tie benefits, firm capacity equivalents shall be added until the LOLE of the isolated New England Control Area is equal to the LOLE of the interconnected New England Control Area.

III.12.9.1. Overview of Tie Benefits Calculation Procedure.

III.12.9.1.1. Tie Benefits Calculation for the Forward Capacity Auction and Annual Reconfiguration Auctions; Modeling Assumptions and Simulation Program.

For each Capacity Commitment Period, tie benefits shall be calculated for the Forward Capacity Auction and the third annual reconfiguration auction using the calculation methodology in this Section III.12.9. For the first and second annual reconfiguration auctions for a Capacity Commitment Period, the tie benefits calculated for the associated Forward Capacity Auction shall be utilized in determining the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values as adjusted to account for any changes in import capability of interconnections with neighboring Control Areas and changes in import capacity resources using the methodologies in Section III.12.9.6.

Tie benefits shall be calculated using the modeling assumptions developed in accordance with Section III.12.9.2 and using the General Electric Multi-area Reliability Simulation (MARS) program.

III.12.9.1.2. Tie Benefits Calculation.

The total tie benefits to New England from all directly interconnected neighboring Control Areas are calculated first using the methodology in Section III.12.9.3. Following the calculation of total tie benefits, individual tie benefits from each qualifying neighboring Control Area are calculated using the methodology in Section III.12.9.4.1. If the sum of the tie benefits from each Control Area does not equal the total tie benefits to New England, then each Control Area's tie benefits are adjusted based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits calculated for each Control Area using the methodology in Section III.12.9.4.2. Following this calculation, tie benefits are calculated for each qualifying individual interconnection or group of interconnections using the methodology in Section III.12.9.5.1. If the sum of the tie benefits from individual interconnections or groups of interconnections does not equal their associated Control Area's tie benefits, then the tie benefits of each individual interconnection or group of interconnections is adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits within the Control Area using the methodology in Section III.12.9.5.2.

III.12.9.1.3. Adjustments to Account for Transmission Import Capability and Capacity Imports.

Once the initial calculation of tie benefits is performed, the tie benefits for each individual interconnection or group of interconnections is adjusted to account for capacity imports and any changes in the import capability of interconnections with neighboring Control Areas, using the methodologies in Section III.12.9.6. Once the import capability and capacity import adjustments are completed, the sum of the tie benefits of all individual interconnections and groups of interconnections for a Control Area, with the import capability and capacity import adjustments, represents the tie benefits associated with that Control Area, and the sum of the tie benefits from all Control Areas, with the import capability and capacity import adjustments, represents the total tie benefits available to New England.

III.12.9.2. Modeling Assumptions and Procedures for the Tie Benefits Calculation.

III.12.9.2.1. Assumptions Regarding System Conditions.

In calculating tie benefits, "at criterion" system conditions shall be used to model the New England Control Area and all interconnected Control Areas.

III.12.9.2.2. Modeling Internal Transmission Constraints in New England.

In calculating tie benefits, all New England internal transmission constraints that (i) are modeled in the most recent Regional System Plan resource adequacy studies and assessments and (ii) are not addressed by either a Local Sourcing Requirement or a Maximum Capacity Limit calculation shall be modeled, using the procedures in Section III.12.9.2.5.

III.12.9.2.3. Modeling Transmission Constraints in Neighboring Control Areas.
The ISO will review annually NPCC's assumptions regarding transmission constraints in all directly interconnected neighboring Control Areas that are modeled for the tie benefits calculations. In the event that NPCC models a transmission constraint in one of the modeled neighboring Control Areas, the ISO will perform an evaluation to determine which interfaces are most critical to the ability of the neighboring Control Area to reliably provide tie benefits to New England from both operational and planning perspectives, and will model those transmission constraints in the tie benefits calculation, using the procedures in Section III.12.9.2.5.

III.12.9.2.4. Other Modeling Assumptions.

A. External transfer capability determinations. The transfer capability of all external interconnections with New England will be determined using studies that take account of the load, resource and other electrical system conditions that are consistent with those expected during the Capacity Commitment Period for which the calculation is being performed. Transfer capability studies will be performed using simulations that consider the contingencies enumerated in sub-section (iii) below.

(i) The transmission system will be modeled using the following conditions:

1. The forecast 90/10 peak load conditions for the Capacity Commitment Period;
2. Qualified Existing Generating Capacity Resources reflecting their output at their Capacity Network Resource level;
3. Qualified Existing Demand Capacity Resources reflecting their Capacity Supply Obligation received in the most recent Forward Capacity Auction;
4. Transfers on the transmission system that impact the transfer capability of the interconnection under study.

(ii) The system will be modeled in a manner that reflects the design of the interconnection. If an interconnection and its supporting system upgrades were designed to provide incremental capacity into the New England Control Area, simulations will assume imports up to the level that the interconnection was designed to support. If the interconnection was not designed to be so comparably integrated, simulations will determine the amount of power that can be delivered into New England over the interconnection.

(iii) The simulations will take into account contingencies that address a fault on a generator or transmission facility, loss of an element without a fault, and circuit breaker failure following the loss of an element or an association with the operation of a special protection system.

B. In calculating tie benefits, New England capacity exports are removed from the internal capacity resources and are modeled as a resource in the receiving Control Area. The transfer capability of external interconnections is not adjusted to account for capacity exports.

III.12.9.2.5. Procedures for Adding or Removing Capacity from Control Areas to Meet the 0.1 Days Per Year LOLE Standard.

In calculating tie benefits, capacity shall be added or removed from the interconnected system of New England and its neighboring Control Areas, until the LOLE of New England and the LOLE of each Control Area of the interconnected system equals 0.1 days per year simultaneously. The following procedures shall be used to add or remove capacity within New England and the interconnected Control Areas to achieve that goal.

A. Adding Proxy Units within New England when the New England system is short of capacity. In modeling New England as part of the interconnected system, if New England is short of capacity to meet the 0.1 days per year LOLE, proxy units (with the characteristics identified in Section III.12.7.1) will be added to the sub-areas that are created by any modeled internal transmission constraints within New England, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the New England Control Area, then proxy units will be added to the entire Control Area. If, as a result of the addition of one or more proxy units, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(b) will be used to remove the surplus capacity.

B. Removing capacity from New England when the New England system is surplus of capacity. In modeling New England as part of the interconnected system, if New England is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in these surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the existing Qualified Capacity, and any amount of proxy units added in that sub-area that is above its 50-50 peak load forecast. Notwithstanding the foregoing, if removing resources will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratios described above for the removal of capacity surplus. If there are no modeled internal transmission constraints in the New England Control Area, then the surplus capacity shall be removed from the entire Control Area.

C. **Adding capacity within neighboring Control Areas when the neighboring Control Area is short of capacity**. In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is short of capacity to meet the 0.1 days per year LOLE, additional capacity will be added to the neighboring Control Area's sub-areas that are created by any modeled internal transmissions constraints, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the Control Area, then capacity will be added to the entire Control Area. The process that the neighboring Control Area utilizes in its resource adequacy study to meet its resource adequacy criterion will be utilized to add capacity to that Control Area. In filing the Installed Capacity Requirement values pursuant to Section III.12.3, the ISO will provide citations to any resource adequacy studies relied upon for these purposes. If, as a result of the capacity addition, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(d) shall be used to remove the surplus capacity.

D. **Removing capacity from neighboring Control Areas when the neighboring Control Area is surplus of capacity**. In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the neighboring Control Area's sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in the surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the installed capacity in the sub-area above its 50/50 peak load forecast. For a sub-area that has a minimum locational resource requirement above its 50/50 peak load forecast, the amount of capacity surplus is the amount of the installed capacity in the sub-area above its minimum locational resource requirement. Notwithstanding the foregoing, if removing resources from a sub-area will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratio of capacity surplus in the sub-area to the total capacity surplus in the those remaining surplus sub-areas. If there are no modeled internal transmission constraints in the neighboring Control Area, then the surplus capacity will be removed from the entire Control Area.

E. **Maintaining the neighboring Control Area's locational resource requirements**. In modeling a neighboring Control Area with internal transmission constraints, all minimum locational resource requirements in the Control Area's sub-areas as established by the neighboring Control Area's installed capacity requirement calculations shall be observed.

III.12.9.3. Calculating Total Tie Benefits.

The total tie benefits with all qualifying directly interconnected neighboring Control Areas shall be calculated by comparing the interconnection state of the New England system with all interconnections to neighboring Control Areas connected with the interconnection state of the New England system with all interconnections with neighboring Control Areas disconnected. To calculate total tie benefits:

A. The New England system shall be interconnected with all directly interconnected neighboring Control Areas and the New England Control Area, and each neighboring Control Area shall be brought to 0.1 days per year LOLE simultaneously by adjusting the capacity of each Control Area, utilizing the methods for adding or removing capacity in Section III.12.9.2.5.

B. Once the interconnected system is brought to 0.1 days per year LOLE, the LOLE of the New England Control Area shall be calculated a second time, with the New England system isolated from the rest of the interconnected system that was brought to 0.1 days per year LOLE.

C. Total tie benefits shall be the sum of the amounts of firm capacity that needs to be added to the isolated New England Control Area at the point at which each interconnection with neighboring Control Areas interconnects in New England to bring the New England LOLE back to 0.1 days per year. This value is subject to adjustment in accordance with Section III.12.9.6.

III.12.9.4. Calculating Each Control Area's Tie Benefits.

III.12.9.4.1. Initial Calculation of a Control Area's Tie Benefits.

Tie benefits from each neighboring Control Area shall be determined by calculating the tie benefits for every possible interconnection state that has an impact on the tie benefit value between the New England system and the target neighboring Control Area. If two or more interconnections between New England and the target neighboring Control Area exist, then all interconnections grouped together will be used to represent the state of interconnection between New England and the target neighboring Control Area. The tie benefits from the target neighboring Control Area shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.4.2.

III.12.9.4.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual Control Area tie benefits calculated in accordance with Section III.12.9.4.1 is different than the total tie benefits from all Control Areas calculated in accordance with Section III.12.9.3, then each Control Area's tie benefits shall be increased or decreased based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits for each individual Control Area, so that the sum of each Control Area's tie benefits, after the pro-ration, is equal to the total tie benefits calculated in accordance with Section III.12.9.3. The pro-rated Control Area tie benefits are subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.5. Calculating Tie Benefits for Individual Ties.

Tie benefits shall be calculated for an individual interconnection or group of interconnections to the extent that a discrete and material transfer capability can be identified for the interconnection or group of interconnections. All interconnections or groups of interconnections shall have equal rights in calculating individual tie benefits, with no grandfathering or incremental tie capability treatment.

For purposes of calculating tie benefits, a group of interconnections refers to two or more AC lines that operate in parallel to form a transmission interface in which there are significant overlapping contributions of each line toward establishing the transfer limit, such that the individual lines in a group of interconnections cannot be assigned individual contributions.

III.12.9.5.1. Initial Calculation of Tie Benefits for an Individual Interconnection or Group of Interconnections.

Tie benefits for an individual interconnection or group of interconnections shall be calculated by calculating tie benefits for each possible interconnection state between the New England system and the individual interconnection or group of interconnections. The tie benefits from that interconnection or group of interconnections shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.5.2.

III.12.9.5.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual interconnection's or group of interconnection's tie benefits calculated in accordance with Section III.12.9.5.1 is different than the associated Control Area's tie benefits calculated in accordance with Section III.12.9.4, then the tie benefits of the individual interconnection or group of interconnections shall be adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits for each interconnection or group of interconnections in that Control Area, so that the sum of the tie benefits for each interconnection or group of interconnections in the Control Area, after the pro-ration, is equal to the total tie benefits for the Control Area calculated in accordance with Section III.12.9.4. The pro-rated tie benefits for each interconnection or group of interconnections is subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.6. Accounting for Capacity Imports and Changes in External Transmission Facility Import Capability.

III.12.9.6.1. Accounting for Capacity Imports.

In the initial tie benefits calculations, capacity imports are modeled as internal resources in New England, and the import capability of the interconnections with neighboring Control Areas is not reduced to reflect the impact of capacity imports. After the initial tie benefits calculations, total tie benefits, tie benefits for each Control Area, and tie benefits from each individual interconnection or group of interconnections shall be adjusted to account for capacity imports using the methodology contained in this Section III.12.9.6.1. For the Forward Capacity Auction and third annual reconfiguration auction, this adjustment shall be applied to the tie benefit values calculated in accordance with Sections III.12.9.3, III.12.9.4 and III.12.9.5 respectively. For the first and second annual reconfiguration auctions, this adjustment shall be applied to the tie benefits values calculated for the Forward Capacity Auction.

- **A.** Capacity imports shall be deducted from the import capability of each individual interconnection or group of interconnections to determine the available import capability of the interconnection or group of interconnections prior to accounting for tie benefits from those interconnections. The transfer capability of an interconnection or group of interconnections shall be determined using the procedures in Section III.12.9.2.4.A.
- **B.** If the tie benefits value of an individual interconnection or group of interconnections, as determined in accordance with Section III.12.9.5, is greater than the remaining transmission import capability of the interconnection or group of interconnections after accounting for capacity imports, the tie benefit value of the individual interconnection or group of interconnections shall be equal to the remaining transmission import capability (taking into

account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2). If the tie benefits value of an individual interconnection or group of interconnections is not greater than the remaining transmission import capability after accounting for capacity imports, then the tie benefit value of the individual interconnection or group of interconnections shall be equal to the value determined in accordance with Section III.12.9.5 (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2).

C. The tie benefits for each Control Area shall be the sum of the tie benefits from the individual interconnections or groups of interconnections with that Control Area, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.

D. The total tie benefits from all qualifying neighboring Control Areas shall be the sum of the Control Area tie benefits, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.

E. For purposes of determining the adjustment to tie benefits to account for capacity imports under this Section III.12.9.6.1, the capacity imports applicable for determining tie benefits for the Forward Capacity Auction shall be the Qualified Existing Import Capacity Resources for the relevant Capacity Commitment Period, and the capacity imports applicable for determining tie benefits for the annual reconfiguration auctions are those Import Capacity Resources that hold Capacity Supply Obligations for the relevant Capacity Commitment Period as of the time the tie benefits calculation is being performed for the annual reconfiguration auction.

III.12.9.6.2. Changes in the Import Capability of Interconnections with Neighboring Control Areas.

For purposes of calculating tie benefits for the Forward Capacity Auction and third annual reconfiguration auction, the most recent import capability values for an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the modeling of system conditions for the tie benefits calculation. In addition, for the first and second annual reconfiguration auctions, any changes to the import capability of an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the adjustment to tie benefits to account for capacity imports under Section III.12.9.6.1.

III.12.9.7. Tie Benefits Over the HQ Phase I/II HVDC-TF.

The tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1 shall be allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.

III.12.10. Calculating the Maximum Amount of Import Capacity Resources that May be Cleared Over External Interfaces in the Forward Capacity Auction and Reconfiguration Auctions.

For external interfaces, Import Capacity Resources shall be allowed in the Forward Capacity Auction and reconfiguration auctions up to the interface limit minus the tie benefits, calculated pursuant to Section III.12.9.1 or 12.9.2 over the applicable interface.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool Participants Committee	))	**Docket No. ER20-___-000**

PREPARED TESTIMONY OF
JONATHAN BLACK
ON BEHALF OF ISO NEW ENGLAND INC.

I. INTRODUCTION

Q: PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A: My name is Jonathan Black. I am employed by ISO New England Inc. (the "ISO") as the Manager of Load Forecasting in System Planning. My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A: I joined the ISO in 2010 and have been the Manager of Load Forecasting for the past four years. In my current capacity, I am primarily responsible for the annual development of the long-term load, energy efficiency, heating and transportation electrification, and solar photovoltaic forecasts, as well as providing technical modeling support for short-term (*i.e.*, next seven day) load forecasting. As part of this role, my group applies a variety of data science, machine learning, and statistical techniques to perform predictive modeling and ongoing analytics for the growing number of factors that impact electricity consumption in New England. This work includes research on and modeling of emerging technologies and trends, as well as developing novel data processes to enable such modeling. Prior to joining the ISO, I spent seven years working as an environmental scientist for Pioneer Environmental, Inc., where I managed hazardous waste site assessment and remediation projects. I have a B.S. in Civil and Environmental Engineering and an M.S. in Mechanical Engineering, both from the University of Massachusetts at Amherst. I am currently pursuing my Doctorate in the interdisciplinary Infrastructure and Environmental Systems program at the University of North Carolina in Charlotte, where I am researching advanced load forecasting techniques.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to explain the revisions to the ISO New England Transmission, Markets and Services Tariff ("Tariff") that improve the methodology that the ISO uses to reconstitute On-Peak Demand Resources[1] and Seasonal Peak Demand Resources[2] (collectively, for purposes of this testimony, "Passive Demand Resources") in

[1] Under Section I.2.2 of the Tariff, 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."

[2] Under Section I.2.2 of the Tariff, a 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."

the long-term gross load forecast (referred to in this testimony as the "gross load forecast").[3]

II. TESTIMONY

A. BACKGROUND

Q: WHAT IS THE GROSS LOAD FORECAST?

A: The ISO's gross load forecast is a probabilistic 10-year projection of gross load for states and the New England region. It includes forecasts of expected monthly and annual gross energy, as well as probabilistic distributions of monthly and seasonal gross peak demand (of which "50/50" and "90/10" are individual points in the probabilistic peak distributions).[4] Gross load reflects load before reductions from market-facing Passive Demand Resources/behind-the-meter photovoltaic systems, and includes the anticipated impacts of heating and transportation electrification, all for which ISO develops separate long-term forecasts each year.

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[3] Passive Demand Resources do not actively participate in energy markets. Their participation is limited to the Forward Capacity Market ("FCM"). Rather than being dispatched, Passive Demand Resources reduce demand once the respective measures are installed.

[4] Additional details are included in the ISO's presentation entitled "Long Term Load Forecast Methodology Overview" which was presented to the New England Power Pool Load Forecast Committee on September 27, 2019. The presentation is available at: https://www.iso-ne.com/static-assets/documents/2019/09/p1_load_forecast_methodology.pdf

Q: WHY DOES THE ISO DEVELOP THE GROSS LOAD FORECAST?

A: Pursuant to Section III.12.8 of the Tariff, the ISO is required to forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecast must be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs, and assumptions must be reviewed with Governance Participants,[5] the state utility regulatory agencies in New England and, as appropriate, other state agencies.

Q: WHAT IS THE GROSS LOAD FORECAST USED FOR?

A: The gross load forecast is used in: (1) determining New England's resource adequacy requirements for future years; (2) evaluating reliability and economic performance of the electric power system under various conditions; (3) planning-needed transmission improvements; and (4) coordinating maintenance and outages of generation and transmission infrastructure assets.

Q: WHAT DATA SOURCES DOES THE ISO USE IN DEVELOPING THE GROSS LOAD FORECAST?

A: In developing the gross load forecast, the ISO uses a variety of data sources. Specifically, to develop estimates of historical and forecast gross load, the ISO uses economic data, weather data, historical electricity prices, load data, Demand Response Resources' data, Energy Efficiency ("EE") performance data, passive distributed generation ("DG") data, and BTM-PV data.

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[5] Capitalized terms used but not defined in this testimony have the meanings ascribed to them in the Tariff.

Q: HOW DOES THE ISO USE DEMAND RESPONSE RESOURCES' DATA, EE PERFORMANCE DATA, PASSIVE DG DATA, AND BTM PV DATA IN THE DEVELOPMENT OF HISTORICAL LOADS?

A: In the development of historical loads, the ISO performs a reconstitution of load by adding historical load reductions from Demand Response Resources, EE, and passive DG. The ISO also reconstitutes BTM PV installations that do not participate in wholesale markets but reduce metered load. Reconstitution of Demand Response Resources, EE, passive DG, and BTM PV to develop historical gross load is performed at the hourly level, for the region, and for each of the six New England states.

Q: PLEASE EXPLAIN, AT A HIGH LEVEL, HOW THE ISO RECONSITUTES ACTIVE DEMAND RESOURCES IN THE GROSS LOAD FORECAST.

A: To reconstitute active demand resources, the ISO adds back into historical loads the metered MW demand reduction of Demand Response Resources.[6]

Q: IS THE ISO PROPOSING TO CHANGE THE METHODOLOGY FOR RECONSTITUTION OF ACTIVE DEMAND RESOURCES?

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[6] Under Section I.2.2 of the Tariff, a 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. A 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 Section III.8.1.1."

A: No. The ISO is not proposing to change the methodology for the reconstitution of active demand resources.[7]

Q: PLEASE EXPLAIN WHY HISTORICAL LOADS NEED TO REFLECT THE LOAD REDUCTIONS FROM PASSIVE DEMAND RESOURCES THAT PARTICIPATE AS SUPPLY-SIDE RESOURCES IN THE FCM.

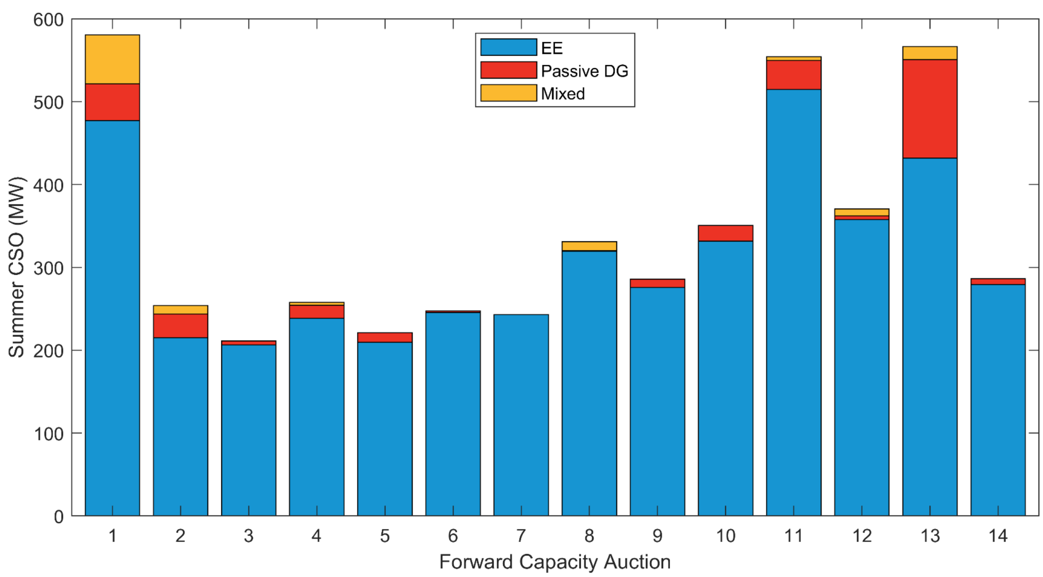
A: Since the beginning of the FCM, Passive Demand Resources have been allowed to participate in the market as supply-side resources, acquiring Capacity Supply Obligations ("CSOs") in the same manner as other supply-side resources. In addition, as I explained above, each year, the ISO develops a gross load forecast using historical loads as one of its inputs. Historical loads must properly account for the load reductions from Passive Demand Resources that participate as supply-side resources in the FCM because, otherwise, those resources would be double-counted (both as load reductions and as capacity supply resources). Accordingly, in developing the gross load forecast, pursuant to Section III.12.8 (d) of the Tariff, the ISO must "reconstitute" (*i.e.,* add back) the demand savings achieved by Passive Demand Resources that participate in the FCM as supply-side resources. "Reconstitution" is purely an accounting mechanism intended to

[7] Active demand resources participate in energy markets by offering demand reductions, which the ISO dispatches based on price. Active demand resources are currently defined in the Tariff as Demand Response Resources. A Demand Response Resource may choose to participate in the FCM and, if it does so, it falls under the definition of Active Demand Capacity Resource in Section I.2.2 of the Tariff, which provides that an 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 [FCM] to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1." Thus, active demand resources participate in the energy market and may or may not participate in the FCM. Reconstitution in the gross load forecast is done for all active demand resources.

align demand assumptions represented by the load forecast with Passive Demand Resources' participation as supply-side resources in the FCM.

Q: WHAT TYPE OF RESOURCES CONSTITUTE THE MAJORITY OF PASSIVE DEMAND RESOURCES THAT ARE RECONSTITUTED IN THE GROSS LOAD FORECAST?

A: EE resources constitute the majority of Passive Demand Resources that are reconstituted in the gross load forecast. The chart below shows the composition of new Passive Demand Resources from the first Forward Capacity Auction ("FCA") to the fourteenth FCA. The composition of total Passive Demand Resource CSOs clearing as new in all fourteen FCAs illustrated is as follows: 91.3% EE, 6.3% passive DG, and 2.4% mixed.



Note: "Mixed" are measures that are a mixture of EE and passive DG.

Q: WHAT IS LOAD REDUCTION QUANTITY FOR EE MEASURES?

A: For EE measures, load reduction quantity is the difference between estimated energy consumption of an installed EE technology and what the energy consumption would have been had a standard technology been in place (*i.e.*, baseline conditions). What load would have been had a standard technology been in place is counterfactual and cannot be observed directly. Hence, measurement and verification studies conducted by EE program administrators assume a baseline load in order to quantify the load reduction produced by an EE measure.

Q: PLEASE EXPLAIN, AT A HIGH LEVEL, HOW THE ISO HAS BEEN RECONSTITUTING EE RESOURCES IN HISTORICAL LOADS SINCE 2010.

A: Starting with the 2010 gross load forecast, to reconstitute EE resources, the ISO has used the performance data that each EE program administrator submits to the ISO. Specifically, each program administrator enters monthly MW values into the ISO's EE measures database ("EEM").[8] The ISO uses those monthly demand values, which reflect demand reductions during seasonal performance hours, as a starting point to estimate the amount of monthly energy and hourly demand needed for EE reconstitution.[9]

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[8] While EEM was not available since the beginning of FCM, all the data that program administrators have provided since the beginning of FCM is now reflected in EEM.

[9] Additional details on the reconstitution of EE resources are included slides 13-17 of the ISO's presentation entitled "Long Term Load Forecast Methodology Overview" which was presented to the New England Power Pool Load Forecast Committee on September 27, 2019. The presentation is available at: https://www.iso-ne.com/static-assets/documents/2019/09/p1_load_forecast_methodology.pdf

Q: WHAT WAS THE ISO'S EXPECTATION FOR THE USE OF EE PERFORMANCE IN THE RECONSTITUTION OF EE RESOURCES, AND HAS THAT EXPECTATION BEEN MET?

A: The ISO had expected that using EE performance (*i.e.,* the amount of total EE measures installed) to reconstitute Passive Demand Resources in the gross load forecast would yield a reconstituted MW value of EE resources that would be commensurate with the MW values of the CSOs that EE resources acquired in the FCM. However, in recent years, the ISO has observed that EE program administrators install and report EE measures in quantities that exceed the CSOs that EE resources have acquired in the FCM. There is no way for the ISO to determine which measures are installed to meet CSOs, and which measures are installed in excess of CSOs. For this reason, the amount of Passive Demand Resources reconstituted in developing the gross load forecast has exceeded the amount of CSOs that Passive Demand Resources have acquired in the FCM.

Q: PLEASE EXPLAIN WHY MEASURE EXPIRATION OVER THE FCM HORIZON SHOULD BE FACTORED IN THE GROSS LOAD FORECAST.

A: While relatively few EE measures have expired[10] up to the 2019-2020 Capacity Commitment Period, a significant number of EE measures are set to expire over the FCM

[10] Section III.13.1.4.1 of the Tariff provides that "[a] Demand Resource may continue to offer capacity into [FCAs] and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life." Thus, an EE measure expires when it reaches the end of its Measure Life, at which point it can no longer participate in the FCM as a capacity resource. Measure Life is defined in Section I.2.2 of the Tariff as "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

horizon (*i.e.,* over subsequent Capacity Commitment Periods associated with already-completed FCAs that are beyond the end of the historical reconstitution period used in developing the ISO's load forecast). However, these trends over the FCM horizon are not well captured by the current methodology, which relies on historical EE performance alone. In addition, measure expiration is factored directly into the calculation of the Qualified Capacity values for FCM participation of existing Passive Demand Resources.[11] Therefore, because the objective is for the Qualified Capacity of cleared Passive Demand Resources and reconstitution amounts to align, measure expiration over the FCM horizon should also be factored into the gross load forecast.

Q: GIVEN THAT USING PERFORMANCE DATA FOR THE RECONSTITUTION OF EE RESOURCES HAS NOT MET THE ISO'S EXPECTATION, WHAT HAS THE ISO DETERMINED?

A: The ISO has determined that the reconstitution methodology for Passive Demand Resource needs to change to better reflect the amount of demand resources that

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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 [FCA] 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."

[11] Passive Demand Resources that have cleared in an auction and can no longer participate as new capacity are existing Passive Demand Resources.

participate in the FCM as supply-side resources. Accordingly, in this filing, the ISO is submitting the Tariff changes that I explain in Section II.B of my testimony.

B. EXPLANATION OF TARIFF CHANGES

Q: PLEASE BRIEFLY DESCRIBE THE COMPONENTS OF THE PROPOSED METHODOLOGY FOR RECONSTITUTION OF PASSIVE DEMAND RESOURCES.

A: The proposed methodology for reconstitution of Passive Demand Resources includes a procedure to account for CSOs that Passive Demand Resources acquire in the FCA, as well as adjustments to account for the differences between the CSOs that Passive Demand Resources acquire in the FCA and the CSOs that those resources acquire in the annual reconfiguration auctions ("ARAs").

1. ACCOUNTING OF CSOs ACQUIRED IN THE FCA

Q: WHAT DATA WILL THE PROPOSED METHODOLOGY FOR RECONSTITUTION OF PASSIVE DEMAND RESOURCES USE TO ACCOUNT FOR CSOs ACQUIRED IN THE FCA?

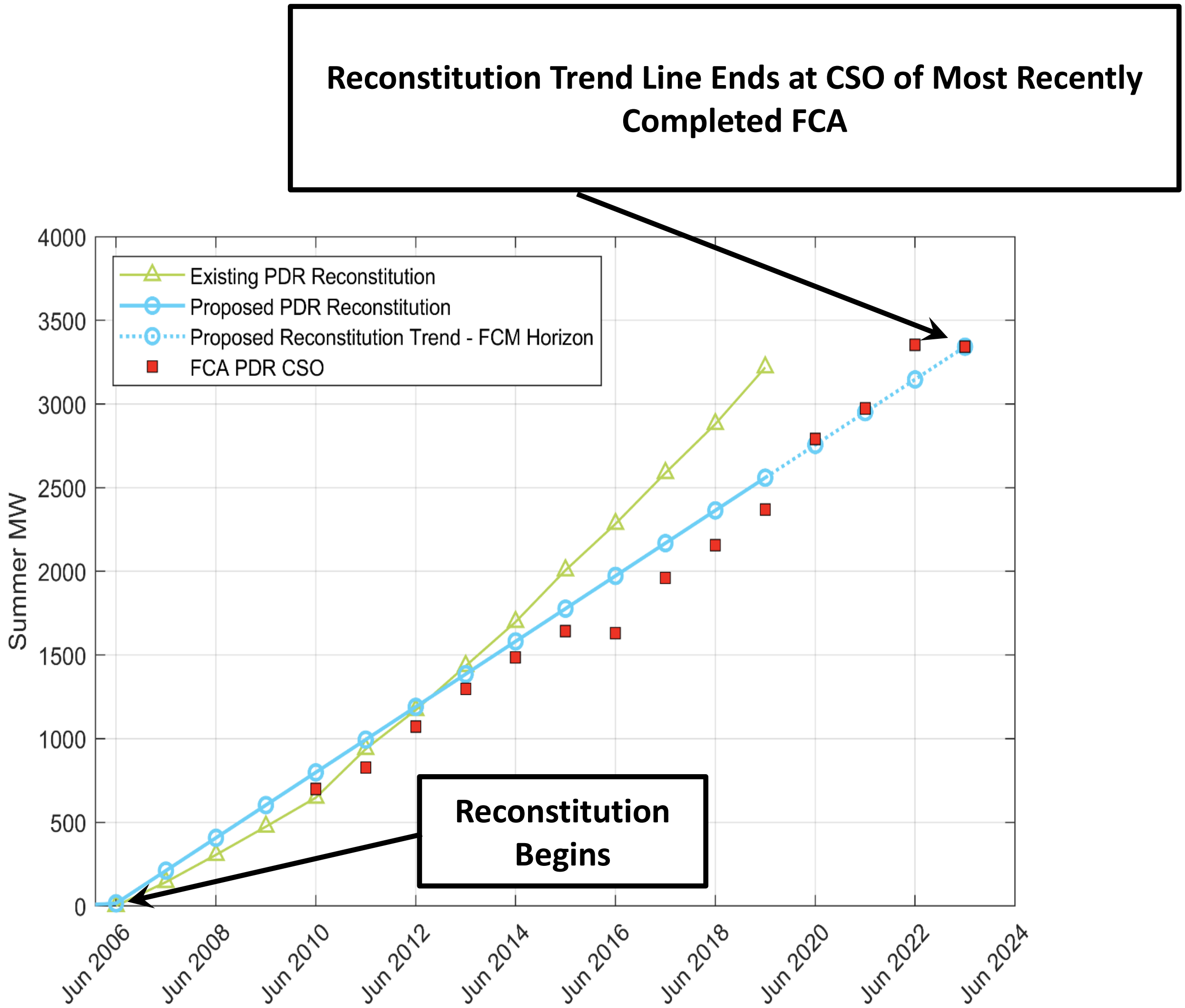
A: Instead of using the data that each EE program administrator enters into EEM to reconstitute Passive Demand Resources in the gross load forecast, under the proposed methodology, the ISO will use the total CSOs acquired by Passive Demand Resources in each FCA to estimate Passive Demand Resources' FCA participation in the upcoming auction.

Q: HOW WILL THE ISO USE THE CSOs ACQUIRED BY PASSIVE DEMAND RESOURCES IN THE MOST RECENTLY CONDUCTED FCA TO RECONSTITUTE THOSE RESOURCES IN THE GROSS LOAD FORECAST?

A: To capture the trends in Passive Demand Resources' FCM participation, the ISO will develop separate trend lines for summer and winter. Specifically, the ISO will develop trend lines between the points in time when summer and winter MW values for Passive Demand Resources are assumed to be zero (*i.e.* June 1, 2006 for summer and December 1, 2006 for winter) and the points in time when summer and winter MW values are reflected by the CSOs that Passive Demand Resources acquired in the most recent FCA for June 1 (summer) and December 1 (winter) of the associated Capacity Commitment Period. To determine the summer and winter MW values to be added back into historical loads, the ISO will interpolate the June 1 and December 1 values for each historical year covered by the trend lines and use these as the appropriate reconstitution values for, respectively, the summer months (*i.e*. April through November), and the winter months (*i.e*. December through March). Below is a diagram showing the methodology as it would have applied to the annual Forecast Report of Capacity, Energy, Loads, and Transmission ("CELT") for 2020.[12] The trend line shown is for the summer. The proposed reconstitution of Passive Demand Resources (blue line) is lower and exhibits a lower slope than the current reconstitution of Passive Demand Resources (green line). As

[12] The CELT is published by May 1 of each year.

already explained, the proposed methodology also requires the development of a trend line for the winter.



Q: WHY ARE JUNE 1, 2006 AND DECEMBER 1, 2006 THE APPROPRIATE STARTING POINTS FOR THE PARTICIPATION TREND LINES?

A: Use of the 2006 starting points results in reconstitution trend lines that reflect the long-term average of Passive Demand Resources' participation in all completed FCAs. This is important because the amount of CSOs that clear in each FCA is unpredictable and can vary significantly between successive auctions, making longer-term averages more consistent and reliable. Furthermore, use of the entire historical period to develop the reconstitution trend lines ensures that the proposed methodology generalizes well for all sub-regions for which the ISO is required to develop forecasts, which includes all New England states, some of which have witnessed greater variation in historical Passive Demand Resources' CSOs over time than New England as a whole. Conversely, use of a methodology that does not readily generalize for all sub-regions would require the ISO to choose inconsistent starting points for different sub-regions in developing each forecast, and perhaps to even change the starting points for some sub-regions as trends change over time.

Q: WHAT ARE THE BENEFITS OF THE PROPOSED METHODOLOGY?

A: The new methodology ensures that reconstituted Passive Demand Resources are appropriately embedded in the gross load forecast by creating a smooth historical reconstitution time series. Such smoothing also enables the inclusion of FCA outcomes extending beyond the historical data currently used for reconstitution. Moreover, by calibrating to the CSOs acquired by Passive Demand Resources in the most recently completed FCA, the proposed reconstitution methodology results in improved accounting for: (1) the amount of Passive Demand Resources that participate in the FCA (which does not include EE installations in excess of EE resources' CSOs); and (2) EE expiring measures that are no longer participating as supply in the FCM.[13]

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[13] Additional information on expiring measures is available in the May 19, 2020 and June 16, 2020 presentations to the Reliability Committee, which are available at: https://www.iso-ne.com/static-assets/documents/2020/05/a08_rc_2020_05_19_lf_reconstitution_method.pptx and https://www.iso-ne.com/static-assets/documents/2020/06/a6_gross_load_forecast_reconstitution_methodology_changes.zip

Q: WHAT ARE THE EFFECTS OF USING THE IMPROVED RECONSTITUTION METHODOLOGY FOR PASSIVE DEMAND RESOURCES IN THE GROSS LOAD FORECAST?

A: Since the improved methodology results in a reconstitution trend for Passive Demand Resources that exhibits a lower level and slope than that of the reconstitution of Passive Demand Resources based on the current methodology, it will result in a lower gross load forecast. This is because the reconstitution will no longer include EE installations in excess of the resources' CSOs, and is net of cumulative EE expiring measures that no longer participate as supply in FCM up through the most recently held FCA. Both of these factors will become embedded as load reductions in the gross load forecast as a result of the improved methodology.

Q: PLEASE QUANTIFY THE EFFECTS THAT THE IMPROVED RECONSTITUTION METHODOLOGY FOR PASSIVE DEMAND RESOURCES WOULD HAVE HAD IF IT HAD BEEN USED IN CELT 2020.

A: Had it been used in CELT 2020, the proposed methodology would have had the effects tabulated below.[14] The resulting forecast reductions, quantified in the rightmost column, start at 652 MW in 2020 due to the lower level of the proposed reconstitution of Passive Demand Resources relative to the current reconstitution of Passive Demand Resources. After 2020, the forecast reductions increase over the forecast horizon due to the lower slope of the proposed Passive Demand Resources' reconstitution trend, which causes the

[14] The gross load forecast is an assumption used in the calculation of the Installed Capacity Requirement ("ICR"). As such, a decrease in the gross load forecast generally results in a decrease in the ICR, all other assumptions being equal.

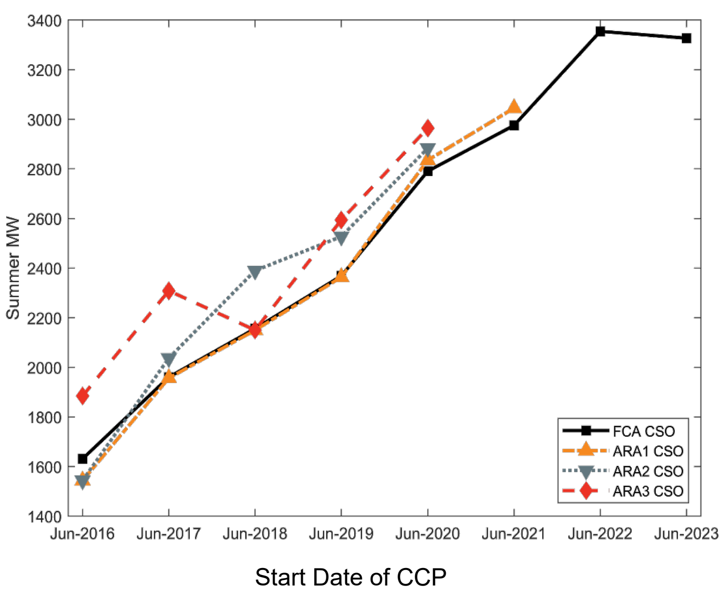
resulting gross load forecast to reflect less gross load growth over time than using the current reconstitution methodology for Passive Demand Resources.

Year	CELT 2020 Summer 50/50 (MW)	CELT 2020 Summer 50/50 Proposed Reconstitution (MW)	Change (MW)
2020	29,224	28,572	-652
2021	29,461	28,742	-719
2022	29,717	28,925	-792
2023	29,977	29,112	-865
2024	30,241	29,294	-947
2025	30,504	29,476	-1,028
2026	30,768	29,659	-1,109
2027	31,034	29,843	-1,191
2028	31,297	30,024	-1,273
2029	31,550	30,195	-1,355

2. ADJUSTMENTS TO ACCOUNT FOR THE DIFFERENCES BETWEEN CSOs ACQUIRED IN THE FCA AND CSOs ACQUIRED IN THE ARAs

Q: WHY WILL THE PROPOSED METHODOLOGY ALSO TAKE INTO ACCOUNT THE RESULTS OF ARAs?

A: The ISO has observed that Passive Demand Resources clear different amounts of CSOs in each of the ARAs than the amount of CSOs they clear in the FCA for the corresponding Capacity Commitment Period. To account for these differences, and in recognition that the proposed reconstitution methodology calibrates the forecast to the amount of CSOs that Passive Demand Resources clear in the FCA, the ISO also proposes to develop unique forecast adjustments tailored for each of the upcoming ARAs and their associated Capacity Commitment Periods. The graph below illustrates the summer CSOs acquired by Passive Demand Resources from all historical FCAs and ARAs associated with Capacity Commitment Periods 2016-2017 through 2023-2024.



As illustrated, CSO amounts acquired through the ARAs are different from those acquired through the FCAs. An observable relationship exists between FCA and ARA CSOs. However, some degree of deviation from this relationship may exist in any single auction. As an example, while CSO values in the third ARA are generally the highest, the value for ARA 3 associated with the 2018-2019 Capacity Commitment Period is lower than the value for ARA 2 associated with that same Capacity Commitment Period.

Q: PLEASE DESCRIBE THE DATA THAT THE ISO WILL USE TO MAKE ADJUSTMENTS TO ACCOUNT FOR THE DIFFERENT AMOUNTS OF PASSIVE DEMAND RESOURCES CLEARING IN THE ARAs.

A: Proper calibration of the gross forecast to the different amounts of Passive Demand Resources acquiring CSOs in the ARAs first requires estimating the differences between the CSOs acquired in FCA and the CSOs acquired in the ARAs for the respective Capacity Commitment Period. To accomplish this, one can use comparisons of recently available ARA CSO data to the FCA CSO values for the relevant Capacity Commitment Period. However, the most recently available ARA data that could help inform the expected clearing of Passive Demand Resources in an upcoming ARA could be from two Capacity Commitment Periods in the past. To illustrate the timing of ARA data availability as it pertains to development of the annual gross load forecast, tabulated below is the timeline of FCAs and ARAs for Capacity Commitment Periods 2019-2020 through 2025-2026.

CCP	CELT Forecast	FCA	ARA1	ARA2	ARA3
2019-20	May-15	FCA 10 Feb '16	ARA1 July '17	ARA2 Sept '18	ARA3 Mar '19
2020-21	May-16	FCA 11 Feb '17	ARA1 July '18	ARA2 Sept '19	ARA3 Mar '20
2021-22	May-17	FCA 12 Feb '18	ARA1 July '19	ARA2 Sept '20	ARA3 Mar '21
2022-23	May-18	FCA 13 Feb '19	ARA1 July '20	ARA2 Sept '21	ARA3 Mar '22
2023-24	May-19	FCA 14 Feb '20	ARA1 July '21	ARA2 Sept '22	ARA3 Mar '23
2024-25	May-20	FCA 15 Feb '21	ARA1 July '22	ARA2 Sept '23	ARA3 Mar '24
2025-26	May-21	FCA 16 Feb '22	ARA1 July '23	ARA2 Sept '24	ARA3 Mar '25

Q: PLEASE PROVIDE THE EQUATIONS THAT THE ISO WILL USE FOR ESTIMATING UPCOMING ARAs CSOs.

A: The equations for estimating upcoming ARA CSOs are as follows:

$$ARA1_{est,\ CCP_n} = FCA_{CCP_n} + \frac{\left(ARA1_{CCP_{n-2}} - FCA_{CCP_{n-2}}\right) + \left(ARA1_{CCP_{n-3}} - FCA_{CCP_{n-3}}\right)}{2}$$

$$ARA2_{est,\ CCP_n} = FCA_{CCP_n} + \frac{\left(ARA2_{CCP_{n-2}} - FCA_{CCP_{n-2}}\right) + \left(ARA2_{CCP_{n-3}} - FCA_{CCP_{n-3}}\right)}{2}$$

$$ARA3_{est,\ CCP_n} = FCA_{CCP_n} + \frac{\left(ARA3_{CCP_{n-1}} - FCA_{CCP_{n-1}}\right) + \left(ARA3_{CCP_{n-2}} - FCA_{CCP_{n-2}}\right)}{2}$$

Where:

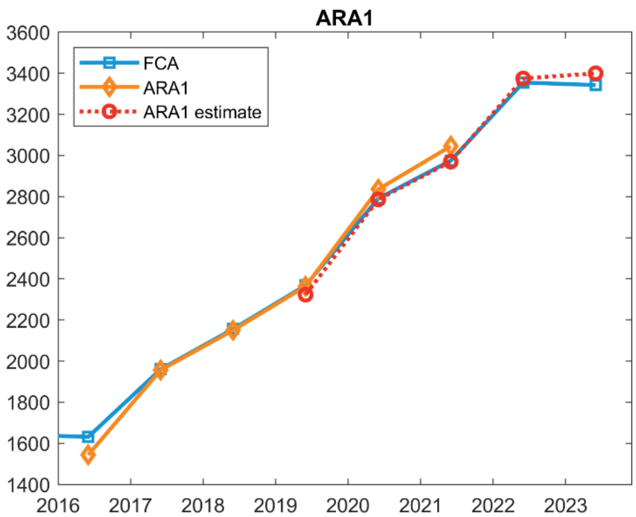
$ARAx_{est,\ CCP_n}$ = PDR CSO estimated to clear the x^{th} (*i.e.*, first, second, or third) Annual Reconfiguration Auction for the n^{th} Capacity Commitment Period.

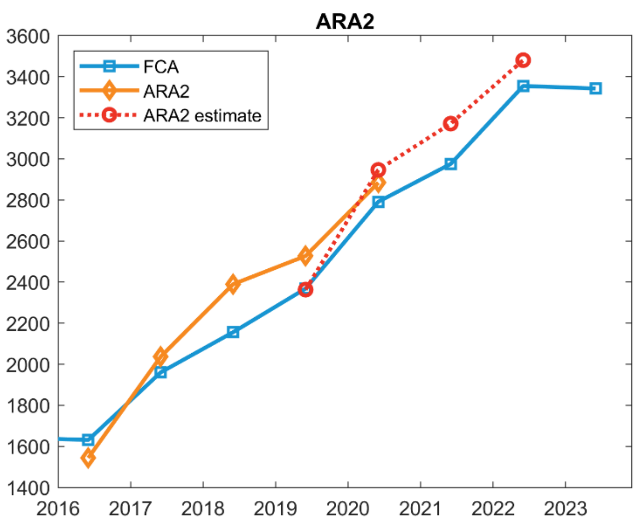
FCA_{CCP_n} = PDR CSO cleared in the FCA for the nth Capacity Commitment Period.

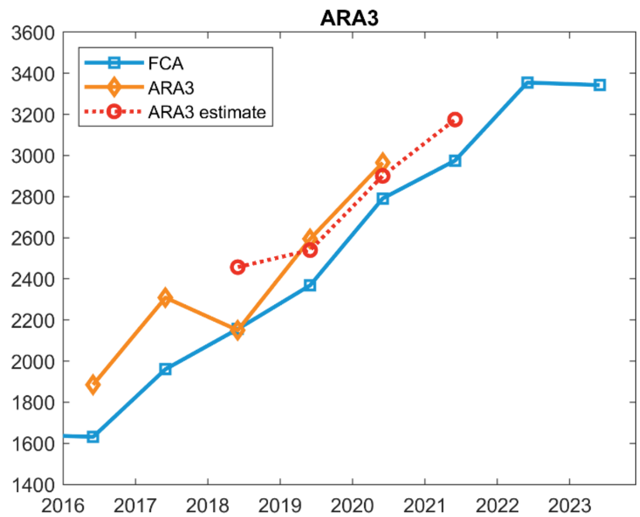
$ARAx_{CCP_{(n-y)}}$ = Actual PDR CSO that cleared the x^{th} (*i.e.*, first, second, or third) Annual Reconfiguration Auction for the n-y Capacity Commitment Period.

Q: PLEASE ILLUSTRATE THE RESULTS OF TESTING THE ARA CSO ESTIMATION METHOD.

A: The following plots show the results of applying the proposed ARA CSO estimation method to historical data. Estimated ARA CSOs are depicted as the dotted red line. Horizontal axes are Capacity Commitment Period dates.


ARA1
FCA
ARA1
ARA1 estimate
3600
3400
3200
3000
2800
2600
2400
2200
2000
1800
1600
1400
2016
2017
2018
2019
2020
2021
2022
2023


ARA2
FCA
ARA2
ARA2 estimate
3600
3400
3200
3000
2800
2600
2400
2200
2000
1800
1600
1400
2016
2017
2018
2019
2020
2021
2022
2023



Q: WHAT CAN YOU CONCLUDE FROM THE TESTING OF THE ARA CSO ESTIMATION METHOD?

A: The results suggest that the method for ARA CSO estimation yields a reasonable approximation of the differences in ARA versus FCA CSOs.

Q: HOW WILL THE ISO CALCULATE THE ADJUSTMENTS TO ACCOUNT FOR THE DIFFERENCES BETWEEN FCA CSOs AND ARA CSOs?

A: The ISO will calculate the adjustments based on the difference between the estimated ARAx CSOs and the Passive Demand Resources "embedded" in the gross load forecast of the appropriate Capacity Commitment Period. Since the proposed reconstitution methodology calibrates the gross load forecast to Passive Demand Resources' CSOs from the most recently completed FCA, the final adjustments for each ARA will be based on the differences between the estimated ARA CSOs and the seasonal MW values interpolated from the reconstitution trend lines. The reconstitution trend lines reflect the amount of Passive Demand Resources embedded in the gross load forecast.

Q: PLEASE PROVIDE THE EQUATIONS TO CALCULATE THE ADJUSTMENTS TO ACCOUNT FOR THE DIFFERENCES BETWEEN FCA CSOs AND ARA CSOs.

A: The following are the equations to calculate the adjustments to account for the difference between FCA CSOs and ARA CSOs are the following:

$$Adjust_{ARA1,\ CCP_n} = ARA1_{est,\ CCP_n} - Reconst_{CCP_n}$$

$$Adjust_{ARA2,\ CCP_n} = ARA2_{est,\ CCP_n} - Reconst_{CCP_n}$$

$$Adjust_{ARA3,\ CCP_n} = ARA3_{est,\ CCP_n} - Reconst_{CCP_n}$$

Where:

$Adjust_{ARAx,\ CCP_n}$ = the adjustment to the gross load forecast for x^{th} (*i.e.*, first, second, or third) Annual Reconfiguration Auction for the n^{th} Capacity Commitment Period.

$Reconst_{CCP_n}$= the PDR CSO value for n^{th} Capacity Commitment Period interpolated from the reconstitution trend line

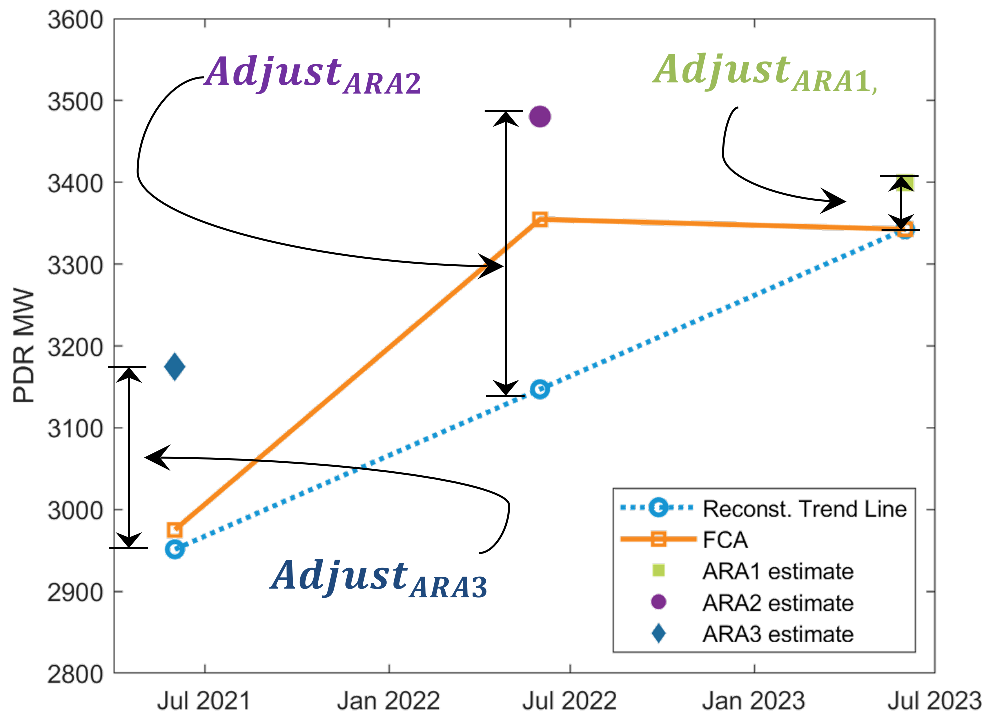
Q: PLEASE PROVIDE AN ILLUSTRATION OF THE LOAD FORECAST ADJUSTMENTS IN CELT 2020.

A: Illustrated below are the ARA forecast adjustments based on the difference between the estimated ARA CSO and the reconstitution trend line.

$Adjust_{ARA1}$ = +57 MW

$Adjust_{ARA2}$ = +333 MW

$Adjust_{ARA3}$ = +224 MW



Q: WHAT ARE THE BENEFITS OF THE PROPOSED ADJUSTMENTS FOR THE ARAs?

A: The proposed framework for adjusting the gross load forecast results in a load forecast that is better calibrated to the differences in the amount of Passive Demand Resources participating in each of the ARAs than the current reconstitution methodology, which includes no such accounting.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare that the foregoing is true and correct.

Jonathan Black

August 10, 2020

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