



October 29, 2015

VIA ELECTRONIC FILING

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

**Re: ISO New England Inc. and New England Power Pool,
Docket No. ER16-___-000;
Part 1 of Two-Part Filing of Demand Response Changes;
Order Requested by December 31, 2015**

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 Committee² (together, the “Filing Parties”), hereby jointly submit this transmittal letter and revised ISO Tariff sections that reflect three sets of changes relating to the participation of demand response resources in the New England wholesale markets (collectively, the “DR Changes”).³

Specifically, the DR Changes encompass: (i) delaying the full integration of demand response into the wholesale markets by one year (the “DR Delay Changes”); (ii) revising the methodology used to derive Demand Response Baselines (the “DR Baseline Changes”); and (iii) modifying the simultaneous auditing requirements of Real-Time Demand Response and Real-Time Emergency Generation Resources (the “DR Simultaneous Auditing Changes”). In support of the DR Changes, this filing also includes the testimony of Henry Y. Yoshimura, the ISO’s

¹ 16 U.S.C. § 824d (2012).

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 (“ISO Tariff”), the Second Restated New England Power Pool Agreement, and the Participants Agreement. Market Rule 1 is Section III of the ISO Tariff.

³ Under New England's RTO arrangements, the rights to make this filing of changes to Market Rule 1 under Section 205 of the Federal Power Act are the ISO's. NEPOOL, which pursuant to the Participants Agreement provides the sole market participant stakeholder process for advisory voting on ISO matters, unanimously supported the changes reflected in this filing and accordingly, joins in this Section 205 filing.

Director of Demand Resource Strategy. This testimony (the “Yoshimura Testimony”) is sponsored solely by the ISO.

This filing letter and its attachments are Part 1 of a two-part contemporaneous submission to the Commission. Due to technical limitations associated with the Commission’s eTariff system, the ISO is not able to submit multiple changes to the same ISO Tariff section that have different effective dates in one submission. Accordingly, Part 1 of the ISO’s overall submission attaches the ISO Tariff changes with a proposed effective date of December 31, 2015, namely, the DR Delay Changes and the DR Baseline Changes. Part 2 of the overall submission attaches the ISO Tariff changes with a proposed effective date of June 1, 2016, namely, the DR Simultaneous Auditing Changes. ***The ISO respectfully requests that an order on both parts of this filing be issued by December 31, 2015.*** The explanation for all of the DR Changes is contained in this Part 1 filing letter. Although the overall filing has been divided into two parts to accommodate the eTariff system, the Commission should treat the submissions as a single filing.

I. 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 operates the New England bulk power system and administers New England’s organized wholesale electricity market pursuant to the ISO Tariff and the Transmission Operating Agreement with the New England transmission owners. In its capacity as an RTO, the ISO also has the objective to assure that the bulk power supply system within the New England Control Area conforms to proper standards of reliability as established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 440 members. The Participants include all of the electric utilities rendering or receiving services under the ISO Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission in *ISO New England Inc. et al.*, 109 FERC ¶ 61,147 (2004), 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 Process 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 [ISO] Tariff, [Transmission Operating Agreement] and the Market Participant Services Agreement included in the [ISO] Tariff.”

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

To the ISO:

Kerim P. May*
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
Tel: (413) 540-4551
Fax: (413) 535-4379
E-mail: kmay@iso-ne.com

To NEPOOL:

Stacy Dimou*
Vice-Chair
NEPOOL Markets Committee
P.O. Box 566
Bangor, ME 04402
Tel: (207) 669-2116
E-mail: stacy.dimou@earthlink.net

David T. Doot, Esq.*
Sebastian M. Lombardi, Esq.*
Day Pitney LLP
242 Trumbull Street
Hartford, CT 06103
Tel: (860) 275-0663
Fax: (860) 881-2493
Email: slombardi@daypitney.com

*Persons designated for service.⁴

II. STANDARD OF REVIEW

The instant revisions are submitted pursuant to Section 205 of the Federal Power Act, which “gives a utility the right to file rates and terms for services rendered with its assets.”⁵ Under Section 205, the Commission “plays ‘an essentially passive and reactive’ role”⁶ whereby it “can reject [a filing] only if it finds that the changes proposed by the public utility are not ‘just and reasonable.’”⁷ 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.”⁸ The revision “need not be the only reasonable methodology, or even the most accurate.”⁹ As a result, even if an intervenor or

⁴ Due to the joint nature of this filing, the Filing Parties respectfully request a waiver of Section 385.203 of the Commission’s regulations to allow the inclusion of more than two persons on the service list in this proceeding.

⁵ *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002).

⁶ *Id.* at 10 (quoting *City of Winfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

⁷ *Id.*

⁸ *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

⁹ *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

the Commission develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.¹⁰

III. DESCRIPTION OF, AND JUSTIFICATION FOR, THE DR CHANGES

A. DR Delay Changes

As noted above, the DR Delay Changes delay the “full integration” of demand response into the New England wholesale markets by one year – from June 1, 2017 until June 1, 2018.

1. Background on Full Integration and Rationale for Delay

The “full integration” of demand response into the wholesale markets refers to the ISO’s plan to enable Demand Response Resources to:

- ***Fully participate in the Day-Ahead and Real-Time Energy Markets:*** this would be accomplished by enabling Demand Response Resources to submit Demand Reduction Offers into the Day-Ahead and Real-Time Energy Markets, which would be used to optimally commit and dispatch such resources in conjunction with all other energy resources such as Generator Assets.¹¹
- ***Provide Operating Reserve and participate in the Forward Reserve Market:*** once Demand Response Resources are integrated into the Energy Markets, Demand Reduction Offers in conjunction with all other Energy Market Supply Offers will be used to co-optimally dispatch and designate Resources to provide Energy and Operating Reserve so as to produce the most economically efficient outcome to meet both energy and reserve requirements.¹²

¹⁰ 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 *City of Bethany*, 727 F.2d at 1136)).

¹¹ The full participation of Demand Response Resources in the Day-Ahead and Real-Time Energy Markets is the second stage of a two-stage implementation process, which was proposed by the ISO to comply with Order No. 745. The Commission largely accepted the ISO’s proposal in the following orders: *ISO New England Inc.*, 138 FERC ¶ 61,042 (2012) (order on the ISO’s Order No. 745 Compliance Filing); *ISO New England Inc. and New England Power Pool*, Docket No. ER12-947-000 (Apr. 17, 2012) (delegated letter order accepting the ISO’s Demand Response FCM Conforming Changes); *ISO New England Inc. and New England Power Pool*, Docket No. ER12-1550-000 (May 29, 2012) (delegated letter order accepting the ISO’s Market Rule 1 Clarifications to the Transition Period Rules for Demand Response); *ISO New England Inc.*, 142 FERC ¶ 61,027 (2013) (order on the ISO’s Market Rule 1 Demand Response FCM Conforming Changes for Full Integration); and *ISO New England Inc.*, 144 FERC ¶ 61,140 (2013) (order on the ISO’s Market Rule 1 Clarifications to the Full Integration Rules for Demand Response and Revisions to Address the Treatment of Net Supply).

¹² The Commission accepted Tariff revisions to fully integrate Demand Response Resources into the reserve markets in *ISO New England Inc. and New England Power Pool*, 150 FERC ¶ 61,007 (2015) (the “January 2015 Order”).

- ***Receive obligations and compensation in the capacity market that are fully comparable with those of dispatchable generation resources:*** with the integration of Demand Response Resources into the energy and reserves markets, all dispatchable resources participating in the capacity market would be subject to and can receive fully comparable obligations and compensation in the capacity market, which reduces potential market distortions.¹³

The delay of the full integration of demand response by one year stems from the uncertainty created by the decision of the U.S. Court of Appeals for the District of Columbia Circuit (“D.C. Circuit”) vacating Order No. 745,¹⁴ which is being reviewed by the U.S. Supreme Court.¹⁵

As explained in the ISO-sponsored Yoshimura Testimony,¹⁶ key to the full integration of demand response into all of the wholesale markets is the integration of Demand Response Resources into the Energy Markets. Without Energy Market integration, not only would Demand Response Resources not be able to participate in the Energy Markets, but these resources also would not be able to provide Operating Reserves (on either a real-time or forward basis), given that Energy Market offers are used to designate and compensate specific resources providing reserves. Furthermore, if Demand Response Resources cannot participate in the Energy Markets, their capacity market obligations and compensation cannot be made fully comparable with those of dispatchable generation resources – for example, if Demand Response Resources were prohibited from Energy Market participation, the requirement that resources with a Capacity Supply Obligation (“CSO”) must participate in the Energy Markets, which is applied to generation resources with a CSO,¹⁷ could not be applied to Demand Response Resources.¹⁸ Therefore, if the U.S. Supreme Court upholds the D.C. Circuit’s order vacating Order No. 745, Demand Response Resource participation in the Energy Markets as currently envisioned in the ISO Tariff would not be permitted, which makes full integration as described above impossible. Under the circumstances, as explained more fully in the Yoshimura Testimony, prudent resource management requires that full integration be delayed by one year.¹⁹

¹³ The Commission accepted the ISO’s Tariff revisions to conform the FCM rules with the rules providing for full integration of Demand Response Resources into the wholesale markets in the following orders: *ISO New England Inc.*, 142 FERC ¶ 61,027 (2013) (as corrected by errata notice issued January 15, 2013); and *ISO New England Inc.*, 146 FERC ¶ 61,175 (2014).

¹⁴ *Electric Power Supply Association v. FERC*, 753 F.3d 216. (D.C. Cir. 2014) (“*EPSA*”).

¹⁵ See *FERC v. Electric Power Supply Association*, No. 14-840, 135 S. Ct. 2049 (May 4, 2015); *EnerNOC, Inc. v. Electric Power Supply Association*, No. 14-841, 135 S. Ct. 2049 (May 4, 2015).

¹⁶ See Yoshimura Testimony at 7.

¹⁷ See ISO Tariff Section III.13.6.1.1.1.

¹⁸ See ISO Tariff Section III.13.6.1.5.1.

¹⁹ See Yoshimura Testimony at 7-8.

2. ISO Tariff Revisions to Implement the Delay in Full Integration

Two main categories of market rule changes are needed to implement the delay – from June 1, 2017 to June 1, 2018 – in the full integration of demand response into the wholesale markets.

First, changes are needed to extend the currently effective rules for Real-Time Demand Response Resources by one year, such that they will continue to apply through the eighth Capacity Commitment Period – *i.e.*, June 1, 2017 through May 31, 2018. These changes involve simply changing the operative date from June 1, 2017, to June 1, 2018 in the appropriate areas of the ISO Tariff.²⁰

Second, the market rules that will be applied to Demand Response Capacity Resources that cleared in the eighth Forward Capacity Auction (“FCA 8”) for the eighth Capacity Commitment Period – *i.e.*, the period June 1, 2017 through May 31, 2018 – must be clarified. FCA 8 has already been conducted and some Demand Response Capacity Resources cleared in that auction under the current set of market rules, which specifies that full integration was going to be in effect as of June 1, 2017. But if full integration is delayed by a year, the specific rules governing Demand Response Capacity Resources for the eighth Capacity Commitment Period become unclear.

To address this issue, the instant market rule changes specify that a Demand Response Capacity Resource that cleared in FCA 8 will be treated as a Real-Time Demand Response Resource during the eighth Capacity Commitment Period. Further, as a result of treating Demand Response Capacity Resources as Real-Time Demand Response Resources, changes must be made to avoid the application of the Shortage Event penalty construct to Demand Response Capacity Resources. The current penalty structure in place for Real-Time Demand Response Resources will apply, and this change will ensure that only one set of adjustments for non-performance is applied to Demand Response Capacity Resources during the eighth Capacity Commitment Period.²¹

²⁰ The date change is made in the following definitions in ISO Tariff Section I.2.2 – Block, Day-Ahead Demand Reduction Obligation, Day-Ahead Energy Market, Demand Reduction Offer, Demand Response Resource, Location, Locational Marginal Price (LMP), Offer Data, Real-Time Demand Reduction Obligation, Re-Offer Period, Resource. The date change is also made in ISO Tariff Sections III.8A, III.8B, III.13.1.4.1, III.13.1.4.3.2, III.13.6.1.5.1, III.13.6.1.5.4.2, III.13.7.1.1.1, III.13.7.2.5.4 and III.13.7.2.5.4.1, and Appendices E1 and E2 to Market Rule 1.

²¹ These changes delete from ISO Tariff Section I.2.2 the definitions of Adjusted Audited Demand Reduction and Hourly Adjusted Audited Demand Reduction. These definitions are not needed since the Shortage Event construct will not be applied to Demand Response Capacity Resources. A definition of Capacity Scarcity Condition has been added to that section. In addition, changes to clarify the treatment of resources that cleared in FCA 8 and to avoid the imposition of Shortage Event penalties, as discussed in the text above, are made in ISO Tariff Sections III.8B.6.2, III.8B.6.3, III.13.1.4.1, III.13.5.3.1.1, III.13.5.3.1.4, III.13.5.3.2, III.13.5.3.2.3, III.13.6.1.5.4.3.3.1, III.13.7.1.1.1, III.13.7.1.5.10, III.13.7.2.7.1.4, and III.13.17.2.7.5.

B. DR Baseline Changes

The DR Baseline Changes replace the current “90/10” Demand Response Baseline methodology with the “mean 10 of 10” methodology, which is less complex to administer and that performs comparably or better as quantified by accuracy, bias, and variability metrics. In addition, as of the date of full integration of demand response, the ISO will also calculate baselines for two additional day types, Saturdays and Sundays/holidays, using a “mean 5 of 5” methodology.

1. Background on Demand Response Baselines and the 90/10 Methodology

A Demand Response Baseline is the expected energy consumption of a demand response asset for each interval of an Operating Day. The baseline is used to estimate the demand reduction achieved by the asset if and when the associated resource is dispatched to reduce consumption.

In 2003, the ISO developed and implemented the current 90/10 Demand Response Baseline methodology to facilitate the participation of demand response resources in the wholesale capacity and energy markets.²² This 90/10 baseline methodology estimates the expected energy consumption of a demand response asset by simulating a ten-day rolling average of meter data from the most recent days on which the associated resource was not dispatched. Under this approach, the ISO takes 90 percent of the previously calculated baseline for each five-minute interval of an Operating Day, and adds to each interval ten percent of the interval meter data from the most recent day on which the associated resource was not dispatched. While the Demand Response Baseline methodology has been revised since 2003, the basic computation algorithm has remained largely unchanged.

As explained in the Yoshimura Testimony, the Demand Response Baseline methodology is being changed because simulating a ten-day rolling average using the current 90/10 baseline methodology is administratively complex and overly labor- and data-intensive.²³ Specifically, the 90/10 baseline methodology uses a recursive algorithm in which each new calculation of a baseline relies primarily on the prior baseline, and each baseline is derived from past meter data. Accordingly, if *any* past meter data is corrected within the ISO’s resettlement period, there will

(...continued)

In Section III.8, a heading is added for Section III.8 to encompass Sections III.8A and III.8B, to clarify that generic references to Section III.8 refer to both Sections III.8A and III.8B, whichever is relevant to the commitment period. Similarly, in Section III, Appendix E1, the Appendix E1 title page is changed to a title page for Appendix E to clarify that generic references to Appendix E refer to both Appendices E1 and E2, whichever is relevant to the commitment period. The Appendix E2 title page is deleted.

Clean-up changes are made in the ISO Tariff Section I.2.2 definition of “Offer Data,” in Section III.8B.4, and in the title of Section III.13.7.2.7.1.4.

²² See Yoshimura Testimony at 11.

²³ See Yoshimura Testimony at 12.

be a very significant “ripple effect” on the calculated baselines from the day of the corrected data forward.²⁴ That is, every time a data correction is made, every subsequent baseline, starting with the baseline for the first day that was computed using the corrected data, needs to be recalculated, meaning that any data corrections during a resettlement period impact all future settlements. Given the possibility of data corrections, the ISO and participants must store and manage many months of data in order to recalculate baselines if any meter data is found to be incorrect, even though the impact of any set of meter data on the calculated baseline diminishes significantly over time. If data problems are found following the end of a data resubmission period, unwinding the impact of the incorrect data on the settlement of the demand response resource is very complex.²⁵

2. Analysis of Alternative Methodologies

In response to these concerns, the ISO analyzed alternative baseline methodologies and compared them to the ISO’s 90/10 baseline methodology to determine which one(s) would:

- perform comparably to, or better than, the existing 90/10 baseline methodology as quantified by accuracy,²⁶ bias,²⁷ and variability²⁸ metrics;
- address the administrative issues with the 90/10 baseline methodology and be transparent and simple to apply; and
- allow for the computation of Demand Response Baselines for three different day-types (non-holiday weekday, Saturday, and Sunday/holiday) at the time of full integration.²⁹

The ISO considered a range of methodologies as potential alternatives to the existing 90/10 baseline methodology. These alternatives varied in the following respects:

- using the statistical median in addition to the mean,
- using a weighted average where more recent days are given greater weight in the baseline computation, and

²⁴ See Yoshimura Testimony at 12.

²⁵ See Yoshimura Testimony at 12.

²⁶ Accuracy is a measure of how closely the estimated baseline predicts the asset’s actual load.

²⁷ Bias is the systematic tendency of a baseline method to over-predict or under-predict actual load.

²⁸ Variability is a measure of how well the baseline predicts actual load under many different conditions (for example, time of day, day of week) and across many different customers.

²⁹ See Yoshimura Testimony at 13.

- taking the average of the most recent 10 non-event weekdays with either the highest or the middle daily average hourly loads.³⁰

The ISO narrowed the alternative methodologies to those that performed very similarly to the current 90/10 baseline methodology with respect to accuracy, bias, and variability metrics. Those methodologies were also examined for administrative complexity, and for suitability for computing baselines of three different day-types.³¹

The ISO determined that baselines based solely on meter data, rather than on (in whole or in part) prior baselines, would reduce administrative complexities. Further, the ISO determined that baseline approaches that limit the period for which historical meter data must be retained reduce the need to store and manage many months of data and limit the possibility of including data in the baseline computation that is from a prior season. (Calculating a baseline using data from a different season lessens the accuracy of the forecasted baseline.)³²

3. Selection of Mean 10 of 10 Methodology; Benefits

Based on the analysis described above, the ISO selected the “mean 10 of 10” methodology to replace the 90/10 baseline methodology in the period before full integration, and to estimate baselines for non-holiday weekday day types after full integration. This methodology has been selected due to its transparency and simplicity.³³

The mean 10 of 10 methodology is an actual (not simulated) ten-day rolling average of meter data from the ten most recent days (of the same day type) on which the demand response resource was not dispatched. For non-holiday weekdays, the pool of historical data used in the baseline computations is limited to the most recent 30 non-holiday weekdays, which corresponds to limiting the historical data used in the baseline computations to six weeks.³⁴

To determine the Demand Response Baseline for a non-holiday weekday, the mean 10 of 10 methodology computes the mean in each interval using meter data from ten non-holiday weekdays chosen from the ten most recent non-holiday weekdays on which the resource was not dispatched from the prior six weeks. Where there are fewer than ten non-holiday weekdays on which the resource was not dispatched within the prior six weeks, the most recent non-holiday weekday(s) on which the resource was dispatched will be included until ten non-holiday weekdays are identified for use in the baseline calculation.³⁵

³⁰ See Yoshimura Testimony at 13.

³¹ See Yoshimura Testimony at 13.

³² See Yoshimura Testimony at 13-14.

³³ See Yoshimura Testimony at 14.

³⁴ See Yoshimura Testimony at 14.

³⁵ See Yoshimura Testimony at 14-15.

As explained in the Yoshimura Testimony, the mean 10 of 10 methodology has several benefits.³⁶ In addition to performing comparably to the 90/10 baseline methodology in terms of accuracy, bias, and variability, the mean 10 of 10 methodology is more transparent and addresses the administrative burden associated with the current 90/10 baseline methodology.

The mean 10 of 10 methodology calculates the current-day baseline using only meter data and does not rely in any part on previously calculated baselines. This change addresses the administrative issues caused by the recursive nature of the 90/10 baseline methodology. As a result, any changes to previously calculated baselines – for example, due to corrected meter data – will not impact subsequent baselines. Limiting the data used in the calculation to a six-week historical period: (1) reduces the need to store and manage many months of data in order to recalculate a baseline, should that prove necessary; and (2) ensures that baselines are calculated using contemporary data rather than historical data (possibly from a different season), which provides a more accurate forecast of expected consumption patterns for the current Operating Day.³⁷

4. Selection of Mean 5 of 5 Methodology for Saturdays and Sundays/Holidays For Period of Full Integration

As noted above, as of the date of the full integration of demand response, the ISO will also calculate baselines for two additional day types, Saturdays and Sundays/holidays, using a “mean 5 of 5” methodology. The ISO will continue use of the mean 10 of 10 methodology for non-holiday weekdays. The mean 5 of 5 methodology calculates a five-day rolling average of meter data from the five most recent like days on which the demand response resource was not dispatched. The additional day types are designed to provide baselines for those day types that are more accurate than applying the baselines of non-holiday weekdays to those day types.³⁸

It is not possible to use ten days of meter data to calculate the baseline for Saturdays, and for Sundays/holidays, while still limiting the historical data used in the calculation to a six-week period. In a six-week period with no holidays, there are only six Saturdays and six Sundays. As mentioned earlier, increasing the historical period beyond six weeks is problematic due to seasonal variation in consumption patterns and increased administrative complexity. For this reason, the use of the mean 10 of 10 methodology would not be appropriate for the Saturdays and Sundays/holidays day types.³⁹

While as a general matter the use of more days in the baseline calculation creates a more accurate picture of typical load, the ISO’s analysis indicates that it is appropriate to use a five-day rolling average (mean 5 of 5) methodology for the Saturday and Sunday/holiday day types.

³⁶ See Yoshimura Testimony at 15.

³⁷ See Yoshimura Testimony at 15.

³⁸ See Yoshimura Testimony at 10.

³⁹ See Yoshimura Testimony at 16.

This methodology computes the mean in each interval using five days of meter data from the five most recent Saturdays or Sundays/holidays on which the demand response resource was not dispatched from the prior six weeks. Where there are less than five Saturdays or Sundays/holidays on which the demand response resource was not dispatched in the prior six weeks, the most recent day(s) of the same day type on which the demand response resource was dispatched will be included until five days are identified for use in the baseline calculation.⁴⁰

In determining how many days to use in the baseline calculation for Saturdays and Sundays/holidays, the ISO considered the historical frequency of operating reserve deficiencies on these day types to estimate the frequency with which scarcity conditions might occur starting with the 2018-2019 Capacity Commitment Period, when baselines for Saturdays and Sundays/holidays are first estimated.⁴¹

Historical data indicate that scarcity conditions rarely occur on Saturdays and Sundays/holidays. Indeed, since the FCM was implemented on June 1, 2010, *all* six-week periods have had at least five Saturdays or Sundays/holidays on which scarcity conditions did *not* occur. According to the Yoshimura Testimony, this means that it is highly likely that a baseline calculated as the average of five days of meter data would not affect the settlement of demand response resources responding to scarcity conditions on Saturdays or Sundays/holidays. Furthermore, the ISO's analysis suggests that a baseline using five days of data is not substantially less accurate than a baseline computed using six days of data.⁴²

5. ISO Tariff Revisions to Implement the Baseline Methodology Changes; Implementation Timeline

Given the resources needed to implement the DR Baseline Changes, the fastest that the ISO would be able to implement the mean 10 of 10 methodology is June 1, 2017 (a year prior to full integration).⁴³ Until then, the ISO would continue using the current 90/10 baseline methodology.

Accordingly, the market rule changes needed to effectuate the Baseline Changes are:

- changes to Section III.8A of the ISO Tariff to incorporate, effective June 1, 2017, the mean 10 of 10 methodology prior to full integration;⁴⁴ and

⁴⁰ See Yoshimura Testimony at 16.

⁴¹ See Yoshimura Testimony at 17.

⁴² See Yoshimura Testimony at 17.

⁴³ See Yoshimura Testimony at 18.

⁴⁴ The language of Section III.8A.1 describing the meter data used to establish the initial baseline is simplified. Sections III.8A.2 and III.8A.3 are modified to specify use of the mean 10 of 10 baseline calculation effective June 1, 2017, and to clarify that the current 90/10 methodology is in effect until then. The titles are modified accordingly.

- changes to Section III.8B of the ISO Tariff, for the full integration period beginning June 1, 2018, to continue use of the mean 10 of 10 methodology for the non-holiday day type, and to implement use of the mean 5 of 5 methodology for Saturdays and Sundays/holidays day types.⁴⁵

C. DR Simultaneous Auditing Changes

The DR Simultaneous Auditing Changes modify the market rules for simultaneous auditing of Real-Time Demand Response (“RTDR”) and Real-Time Emergency Generation (“RTEG”) Resources.

1. Background: Purpose of Auditing

RTDR and RTEG Resources⁴⁶ are audited each season to establish their capability for providing capacity to the electric system in that season. During an audit, the resource is sent a Dispatch Instruction and the resource’s performance in response to that instruction is measured,⁴⁷ which is used to establish the resource’s Demand Reduction Value. These audits serve various purposes including establishing the resource’s capability for operational planning, determining whether the resource has achieved commercial operation (which affects the refunding of any Financial Assurance collected from the resource’s Market Participant), and determining settlement in seasons when the resource was not dispatched in response to an actual capacity deficiency event. Where an RTDR Asset and an RTEG Asset are located at the same

⁴⁵ The description of the three day types is modified in Section III.8B. In Section III.8B.1, Section III.8B.3 is included in the list of sections where Net Supply will be used in the Demand Response Baseline calculations. Section III.8B.2 is modified to specify the initial baseline calculations for non-holiday weekdays, Saturday, and Sundays/holidays beginning June 1, 2018. Sections III.8B.2 and III.8B.3 include the same language clarification as in Section III.8A.1 and Section III.8B.2 simplifies the description of relationship between establishment of the initial baseline and submission of Demand Reduction Offers. Section III.8B.3 is modified to specify the baseline calculation (mean 10 of 10) for non-holiday weekdays beginning June 1, 2018. Section III.8B.4 is divided into two sections (Sections III.8B.4.1 and III.8B.4.2), the former addressing Saturdays and the latter addressing Sundays/holidays, both for the period beginning June 1, 2018. Section III.8B.4.1 specifies the use of the mean 5 of 5 methodology for Saturdays, and Section III.8B.4.2 specifies the use of the mean 5 of 5 methodology for Sundays/holidays. Section III.8B.6.2 specifies that unadjusted baseline values submitted as meter data during forced or scheduled curtailments are day type-specific, and corrects a typographical error.

Section III.8B.5 includes tariff language describing the demand response baseline adjustment factor. This language, addressed in the January 2015 Order (at PP 4, 14-15), was not filed with the Commission because of an administrative error.

⁴⁶ An RTDR or RTEG *Resource* is generally an aggregation of RTDR or RTEG *Assets*, respectively, located in the same Dispatch Zone. An RTDR Asset is generally a single end-use facility. An RTEG Asset is an emergency generator located behind the Retail Delivery Point of a single end-use facility.

⁴⁷ The performance of an RTDR or RTEG Asset is measured by comparing the metered demand of the asset during the period of dispatch to its adjusted Demand Response Baseline. The performance of an RTDR or RTEG Resource is the sum of the performances of its constituent assets.

facility, the current rules require that they be audited simultaneously to prevent over-crediting the combined capacity of the assets.

2. Explanation and Justification of DR Simultaneous Auditing Changes

The DR Simultaneous Auditing Changes modify the simultaneous auditing rules for RTDR and RTEG Resources⁴⁸ to reduce the burden of having to dispatch all RTDR Assets that are included in a RTDR Resource but are not co-located with an RTEG Asset an additional time during a season in order to establish audit values for a few co-located RTDR and RTEG Assets. In short, the current rules can require the dispatch of far more assets than necessary to establish the needed audit values. Under the new approach, Market Participants with RTDR and RTEG Resources will have the option to audit their RTEG Resources by simultaneously dispatching *only the co-located RTDR Assets* at the time of the RTEG Resource audit. Alternatively, Market Participants may continue to audit their RTEG Resources by simultaneously dispatching the entire RTDR Resource associated with co-located RTDR and RTEG Assets, as under the current rules. The ISO plans to implement the DR Simultaneous Auditing Changes on June 1, 2016.⁴⁹

As mentioned above, the simultaneous audit requirement is intended to prevent over-crediting the combined capacity of RTDR Assets and RTEG Assets located at the same facility. For example, assume a facility with 500 kW of baseline energy consumption and a 300 kW emergency generator. If this facility participates as an RTDR Asset, it may be able to interrupt 300 kW of consumption in response to a dispatch instruction, resulting in a 300 kW demand reduction value. If the RTEG Asset at the same facility is audited at a separate time, its dispatch (assuming that it performs at its full capacity) would result in a 300 kW demand reduction value. The sum of the two demand reduction values is 600 kW. However, the demand reduction value of this facility should not exceed 500 kW (its baseline energy consumption) if this facility is not capable of Net Supply.⁵⁰ This example shows that allowing such facilities to audit the RTEG Asset separately from the RTDR Asset could over-credit the total capacity of the facility. Requiring the RTEG Asset and the RTDR Asset to be audited simultaneously ensures that the facility's demand reduction value is limited to 500 kW.⁵¹

Where an RTDR Asset and RTEG Asset are co-located at an end-use facility, the current ISO Tariff provisions require that the entire RTDR Resource – *which may include RTDR Assets at other locations* – be audited simultaneously with an audit of the RTEG Resource. This requirement can lead to significant inefficiency, however, because RTDR Resources are more likely than RTEG Resources to be dispatched in the normal course of a season. (This is because

⁴⁸ A single end-use facility with an emergency generator could participate in the wholesale market as an RTDR Asset and as an RTEG Asset.

⁴⁹ See Yoshimura Testimony at 19-20.

⁵⁰ The ISO Tariff defines Net Supply as energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation. Most facilities with emergency generators are not capable of Net Supply.

⁵¹ See Yoshimura Testimony at 20.

RTDR Resources are dispatched in response to OP-4, Action 2,⁵² whereas RTEG Resources are dispatched in response to the less frequent OP-4, Action 6.⁵³) It is more common that the Capacity Value of an RTDR Resource is established in response to an OP-4 event in a season, but the Capacity Value of an associated RTEG Resource is not. The current simultaneous audit requirement necessitates that the entire RTDR Resource, which may have already been dispatched in response to OP-4, be dispatched once again in the same season, even if there is only one facility with a co-located RTDR and RTEG Asset.⁵⁴

The market rule changes reduce the burden of having to audit the entire RTDR Resource at the time of the RTEG Resource audit by allowing Market Participants to audit their RTEG Resources by simultaneously dispatching *only the co-located RTDR Assets* if the RTDR Resource has already established a Seasonal DR Audit value by performing in response to OP-4 dispatch. This approach preserves the intent of the simultaneous auditing requirement – *i.e.*, to prevent the over-crediting of the capacity of RTDR Assets and RTEG Assets located at the same facility – but eliminates the needless re-auditing of the remainder of the RTDR Resource. Market Participants will still be able to audit their RTEG Resources by simultaneously dispatching the entire RTDR Resource associated with co-located RTDR and RTEG Assets if they so choose.⁵⁵

As explained in the Yoshimura Testimony, under the rule changes, in the unlikely event of a simultaneous dispatch of both RTDR and RTEG Resources in response to OP-4 in a season, Market Participants can use the performance of these resources during the simultaneous dispatch to establish audit values. That is, Market Participants can use a coincident OP-4 activation of RTDR and RTEG Resources with co-located assets to establish Seasonal DR Audit values for each resource. Because a coincident dispatch of RTDR and RTEG Resources with co-located assets satisfies the simultaneous audit requirement, provided that the dispatch of both resources is of sufficient duration, it is appropriate to allow a concurrent dispatch of RTDR and RTEG Resources to establish audit values.⁵⁶

⁵² ISO New England Operating Procedure No. 4, (“OP-4”) establishes the criteria and actions to be taken during capacity deficiencies. See http://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op4/op4_rto_final.pdf.

⁵³ This action was last called in year 2006. OP-4, Action 6 allows the ISO to implement a voltage reduction of 5% of normal operating voltage (requiring more than 10 minutes to attain) and to dispatch RTEG resources in the amount and location required. The last major revision of OP-4 took effect in June 2010 with the implementation of the Forward Capacity Market. At that time, OP-4 was consolidated into 11 actions (from 16 actions). What is now known as OP-4, Action 6 was called OP-4, Action 12 in year 2006.

⁵⁴ See Yoshimura Testimony at 21.

⁵⁵ See Yoshimura Testimony at 21-22.

⁵⁶ See Yoshimura Testimony at 22.

3. ISO Tariff Revisions to Implement the Simultaneous Auditing Changes

All of the changes to the ISO Tariff needed to effectuate the revisions to the simultaneous auditing requirement are contained in Section III.13.6.1.5.4:

- Section III.13.6.1.5.4.1 (“General Auditing Requirements for Demand Resources Excluding Demand Response Capacity Resources”), in paragraph (b), incorporates the exception from the simultaneous audit of the entire RTDR Resource with an RTEG Resource audit including the appropriate section reference. In addition, since an RTEG Resource can have assets behind more than one Retail Delivery Point, the word "the" is replaced with "any.”
- Section III.13.6.1.5.4.3.3 (“Use of Event Performance Data to Satisfy Audit Requirements for Certain Resources”) reflects the following changes:
 - The first paragraph is modified such that it applies only to those RTDR and RTEG Resources that are not subject to the simultaneous audit requirement. Minor clarifications are made, as well.
 - In the first paragraph, “Demand Response Resource Notification Time” is modified to “notification time” because the defined term is related to Demand Response Resources and not RTDR or RTEG Resources.
 - A new second paragraph is inserted that specifies the new audit procedures for RTDR and RTEG Resources that are subject to the simultaneous audit requirement. This section requires that only the co-located RTDR Assets need be simultaneously dispatched at the time of the RTEG Resource audit. The revisions also include a description of the 60-minute period used in establishing audit values depending on whether the RTDR Resource was dispatched individually, or concurrently with a RTEG Resource with co-located assets.
 - A new third paragraph is added, specifying how a coincident activation of RTDR and RTEG Resources with co-located assets can use the simultaneous portion of the activation to satisfy the simultaneous audit requirement.
 - The last sentence of the first paragraph is relocated to a new fourth paragraph, as this requirement for the use of event performance data to satisfy the audit requirement applies whether or not the RTDR and RTEG Resources are subject to the simultaneous audit requirement. Also, the wording in this new paragraph is clarified to make it consistent with both the first and second paragraphs. This paragraph defines which 60-minute period is used to determine audit performance in the case of (1) a concurrent dispatch of the RTDR and RTEG Resources, or (2) where the resources were not dispatched concurrently.

IV. STAKEHOLDER PROCESS

The DR Changes were vetted through the complete NEPOOL Participant Processes and received the unanimous support of the NEPOOL Participants Committee.

At its August 11-13, 2015 meeting, the NEPOOL Markets Committee voted unanimously (via a show of hands vote) to recommend NEPOOL Participants Committee support for the DR Delay Changes. The NEPOOL Participants Committee, at its September 11, 2015 meeting, voted unanimously to support the DR Delay Changes as part of its Consent Agenda.⁵⁷

At its September 2-3, 2015 meeting, the NEPOOL Markets Committee voted unanimously (via a show of hands vote) to recommend NEPOOL Participants Committee support for the DR Baseline Changes and the DR Simultaneous Auditing Changes. The NEPOOL Participants Committee, at its October 2, 2015 meeting, voted unanimously to support the DR Baseline Changes and the DR Simultaneous Auditing Changes as part of its Consent Agenda.⁵⁸

V. REQUESTED EFFECTIVE DATES

The ISO requests a December 31, 2015 effective date for the DR Delay Changes and the DR Baseline Changes. The ISO requests a June 1, 2016 effective date for the DR Simultaneous Auditing Changes. Pursuant to Section 35.3(a)(1) of the Commission's Rules of Practice and Procedure, tariff revisions such as those presented here must be filed with the Commission "not less than sixty days nor more than one hundred twenty days prior to the date on which the electric service is to commence and become effective."⁵⁹ Because the requested effective date of June 1, 2016 is more than 120 days after the date of this filing, the ISO respectfully requests waiver of this requirement of Section 35.3(a)(1), so that an order is issued on all of the DR Changes by December 31, 2015. Good cause exists to permit such a waiver, because the Market Participants need certainty regarding the scope of new auditing approach well in advance of the June 1, 2016 effective date of these changes.

⁵⁷ The Consent Agenda for a Participants Committee meeting, similar to the Consent Agenda for a Commission open meeting, is a group of actions (each recommended by a Technical Committee or subgroup established by the Participants Committee) to be taken by the Participants Committee through approval of a single motion at a meeting. All recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. The Participants Committee's unanimous approval of the September 11, 2015 Consent Agenda included its support for the DR Delay Changes.

⁵⁸ The Participants Committee's unanimous approval of the October 2, 2015 Consent Agenda included its support for the DR Baseline Changes and the DR Simultaneous Auditing Changes.

⁵⁹ 18 C.F.R. § 35.3(a)(1) (2015).

VI. 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.⁶⁰ However, the DR Changes are not traditional "rates," and the Filing Parties are not traditional investor-owned utilities. In light of these circumstances, the Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13, and request a waiver of Section 35.13 of the Commission's regulations to the extent the content or form deviates from the specific technical requirements of the regulations.

35.13(b)(1) - materials included herewith are as follows:

- ◆ This transmittal letter;
- ◆ Blacklined ISO Tariff sections reflecting the revisions submitted in this filing;
- ◆ Clean ISO Tariff sections reflecting the revisions submitted in this filing;
- ◆ Testimony of Henry Y. Yoshimura, the ISO's Director of Demand Resource Strategy, sponsored solely by the ISO;
- ◆ List of governors, utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and other entities, to which a copy of this filing has been sent.

35.13(b)(2) – See Section V of this filing letter for the requested effective dates.

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

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

⁶⁰ 18 C.F.R. § 35.13 (2015).

35.13(b)(5) - The reasons for this filing are discussed in Section III of this transmittal letter.

35.13(b)(6) - The ISO's approval of the revision is evidenced by this filing. With respect to NEPOOL's support, as noted in Section IV of this transmittal letter, the DR Changes reflect the outcome of the Participant Processes required by the Participants Agreement, and are unanimously supported by the NEPOOL Participants Committee.

35.13(b)(7) - The Filing Parties do not have 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.

VII. CONCLUSION

For the reasons stated herein, the Filing Parties respectfully request that the Commission accept the DR Changes as filed, without condition, suspension, or hearing.

Respectfully submitted,

ISO NEW ENGLAND INC.

By: /s/ Kerim P. May

Kerim P. May

Jennifer Wolfson

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040-2841

(413) 540-4551

NEPOOL PARTICIPANTS COMMITTEE

By: /s/ Sebastian M. Lombardi

Sebastian M. Lombardi, Esq.

Day Pitney LLP

242 Trumbull Street

Hartford, CT 06103

(860) 275-0663

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

- (a) words denoting the singular include the plural and vice versa;
- (b) words denoting a gender include all genders;
- (c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;
- (d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;
- (e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;
- (f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;
- (g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;
- (h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;
- (i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;
- (j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

other late payment or charge, provided such payment is made on such next succeeding Business Day);

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

I.2.2. Definitions:

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

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

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

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

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

~~**Adjusted Audited Demand Reduction** is the Audited Demand Reduction of a Demand Response Resource adjusted in accordance with Section III.13.7.1.5.10.1.1.~~

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity's right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource is any Resource eligible to provide Regulation that is not registered as a different Resource type.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annualized FCA Payment is used to determine a resource's availability penalties and is calculated in accordance with Section III.13.7.2.7.1.2(b) of Market Rule 1.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

APR-1 means the first of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-2 means the second of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-3 means the third of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

Asset is a generating unit, interruptible load, a component of a demand response resource or load asset.

Asset Registration Process is the ISO business process for registering a physical load, generator, or tie-line for settlement purposes. The Asset Registration Process is posted on the ISO's website.

Asset Related Demand is a physical load that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of one or more individual end-use metered customers receiving service from the same point or points of electrical supply, with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net risk-adjusted going forward costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Audited Demand Reduction is the seasonal claimed capability of a Demand Response Resource as established pursuant to Section III.13.6.1.5.4.

Audited Full Reduction Time is the Offered Full Reduction Time associated with the Demand Response Resource's most recent audit.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a generating unit change its output while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (iv) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response

Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs

associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart CIP Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 utilizing data from Table 6 of Appendix A to this Schedule 16, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Blackstart Station's costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Blackstart CIP O&M Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a Blackstart Station's operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision of Blackstart Service.

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual compensation, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, for a Designated Blackstart Resource's operating and maintenance costs associated with the provision of Blackstart Service (except for operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT, which also encompasses "System Restoration and Planning Service" under the predecessor version of Schedule 16.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and

which includes a commitment to provide Blackstart Service under a “Signature Page for Schedule 16 of the NEPOOL OATT” that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station’s capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Station-specific Rate CIP Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station’s capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for

Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (for Capacity Commitment Periods commencing on or after June 1, 2018⁷, Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capability Year means a year's period beginning on June 1 and ending May 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on July 14, 2014.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Clearing Price Floor is described in Section III.13.2.7.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible, equal to that Market Participant's Capacity Requirement (if any) adjusted to account for any relevant Capacity Load Obligation Bilaterals, as described in Section III.13.7.3.1 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on July 14, 2014.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Requirement is described in Section III.13.7.3.1 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in the rules filed with the Commission on January 17, 2014, and accepted by the Commission on May 30, 2014.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Right (CTR) is a financial right that entitles the holder to the difference in the Net Regional Clearing Prices between Capacity Zones for which the transfer right is defined, in the MW amount of the holder's entitlement.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Value is the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.7.1.5 of Market Rule 1.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Category A Designated Blackstart Resource is a Designated Blackstart Resource that has committed to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 and has not been converted to a Category B Designated Blackstart Resource.

Category B Designated Blackstart Resource is a Designated Blackstart Resource that is not a Category A Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each power year, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset in all Load Zones. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.A of that policy.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer

paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

- (1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and
- (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry (\$/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailement is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(iii) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2018⁷, Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts of a Demand Response Resource scheduled by the ISO as a result of the Day-Ahead Energy Market, multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1 and purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2018⁷.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(ii) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(i) of Market Rule 1.

Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Program. The Day-Ahead Load Response Program allows Market Participants with registered Load Response Program Assets to make energy reduction offers into the Day-Ahead Load Response Program concurrent with the Day-Ahead Energy Market.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(iv) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(h) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(g) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2018~~7~~, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.E1.6 and Section III.E2.6.

Demand Reduction Value is the quantity of reduced demand calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

Demand Resource is a resource defined as Demand Response Capacity Resources, On-Peak Demand Resources, Seasonal Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area pursuant to Appendix III.E1 and Appendix III.E2 of Market Rule 1, or during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

Demand Resource Commercial Operation Audit is an audit initiated pursuant to Section III.13.6.1.5.4.4.

Demand Resource Forecast Peak Hours are those hours, or portions thereof, in which, absent the dispatch of Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast.

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Operable Capacity Analysis means an analysis performed by the ISO estimating the expected dispatch hours of active Demand Resources given different assumed levels of Demand Resources clearing in the primary Forward Capacity Auction.

Demand Resource Performance Incentives means the additional monthly capacity payment that a Demand Resource may earn for producing a positive Monthly Capacity Variance in a period where other Demand Resources yield a negative monthly capacity variance.

Demand Resource Performance Penalties means the reduction in the monthly capacity payment to a Demand Resource for producing a negative Monthly Capacity Variance.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and the pumping load associated with pumped storage generators) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2. The demand reduction of a Demand Response Asset is the difference between the Demand Response Asset's actual demand measured at the Retail Delivery Point, which could reflect Net Supply, at the time the Demand Response Resource to which the asset is associated is dispatched by the ISO, and its adjusted Demand Response Baseline.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8A or Section III.8B.

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

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will

be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Regulation Resource is a Real-Time Demand Response Resource eligible to provide Regulation.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2018⁷.

Demand Response Resource Notification Time is the minimum time, from the receipt of a Dispatch Instruction, that it takes a Demand Response Resource that was not previously reducing demand to start reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the time required from the time a Demand Response Resource that was not previously reducing demand starts reducing demand in response to a Dispatch Instruction and the time the resource achieves its Minimum Reduction.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for generation and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) is the Dispatch Rate expressed in megawatts.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Resources, change External Transactions, or change the status of a Dispatchable Asset Related Demand in

accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output, consumption or demand reduction level of each generating Resource, Dispatchable Asset Related Demand and Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.13.1.4.6.1.

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions and must meet the technical requirements specified in the ISO New England Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources, however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation resources directly connected to end-use customer load and located behind the end-use customer's meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time

Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a wind resource must not exceed.

DR Auditing Period is the summer DR Auditing Period or winter DR Auditing Period as defined in Section III.13.6.1.5.4.3.1.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output level to which a Resource would have been dispatched, based on the Resource's Supply Offer and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a resource that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the resource's Supply Offer. This represents the highest MW output a Market Participant has offered for a resource for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit for all hours in which a resource has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for Resources with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for Resources without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Resource and with meeting all environmental regulations and licensing limits, and (c) for Resources undergoing Facility and Equipment Testing or auditing, the level to which the Resource requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for non-dispatchable Resources the output level at which a Market Participant anticipates its non-dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the set of Supply Offer values that are used for NCPC calculation purposes as specified in Section III.F.1.a.

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electronic Dispatch Capability is the ability to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of generating units and Dispatchable Asset Related Demands and the ability to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Resources.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum generation amount, in MWs, that a generating unit can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange as determined by the ISO settlement process for the Energy Market.

Energy Offer Cap is \$1,000/MWh.

Energy Offer Floor is negative \$150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours and Energy Non-Zero Spot Market Settlement Hours.

Enrolling Participant is the Market Participant that registers Customers for the Load Response Program.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORD) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, the Capacity Requirement from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Estimated Net Regional Clearing Price (ENRCP) is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted by certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, and, subject to ISO evaluation, for the Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

Existing Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.1 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; (v) is capable of receiving and acknowledging a Dispatch Instruction electronically; and (vi) has satisfied its Minimum Time Between Reductions.

Fast Start Generator means a generating unit that the ISO may dispatch within the hour through electronic dispatch and that meets the following criteria: (i) minimum run time does not exceed one hour; (ii) minimum down time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Payment is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider,

or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Forecast Hourly Demand Reduction means the estimated maximum quantity of energy reduction (MWh), measured at the end-use customer meter that can be produced by a Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource, in each hour of an Operating Day. For a Real-Time Emergency Generation Asset that is metered at the generator and associated with a Real-Time Emergency Generation Resource, the Forecast Hourly Demand Reduction means the estimated maximum generator output (MWh) in each hour of an Operating Day.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual descending clock auction in the Forward Capacity Market, as described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is \$14,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a “Non-Market Participant FTR Customers” and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC’s Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a generator that has been registered in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

~~Hourly Adjusted Audited Demand Reduction is calculated in accordance with Section III.13.7.1.5.10.1.2.~~

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event

Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.2.7.1.1.1(a) of Market Rule 1.

Hourly Real-Time Demand Response Resource Deviation means the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.7.3.1.

Hourly Real-Time Emergency Generation Resource Deviation is calculated pursuant to Section III.13.7.1.5.8.3.1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit,

plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadequate Supply is defined in Section III.13.2.8.1 of Market Rule 1.

Inadvertent Energy Revenue is defined in Section III.3.2.1(k) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(l) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled generation at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Insufficient Competition is defined in Section III.13.2.8.2 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the “Large Generator Interconnection Agreement”, the “Small Generator Interconnection Agreement”, or the “Elective Transmission Upgrade Interconnection Agreement” pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the “Large Generator Interconnection Procedures”, the “Small Generator Interconnection Procedures”, or the “Elective Transmission Upgrade Interconnection Procedures” pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Intermittent Power Resource is defined in Section III.13.1.2.2.2 of Market Rule 1.

Intermittent Settlement Only Resource is a Settlement Only Resource that is also an Intermittent Power Resource.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means generating resources that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, or Real-Time Demand Response Event Hours to other hours and reduce the amount of capacity needed, while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, chilled water storage, and other forms of electricity storage.

Load Response Program means the program implemented and administered by the ISO to promote demand side response as described in Appendix E to Market Rule 1.

Load Response Program Asset means one or more individual end-use metered customers that report load reduction and consumption, or generator output as a single set of values, are assigned an identification number, that participate in the Load Response Program and which encompass assets registered in the Real-Time Price Response Program or Real-Time Demand Response Assets, and are further described in Appendix E of Market Rule 1.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA.

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade or a Public Policy Transmission Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone or Hub. For Capacity Commitment Periods commencing on or after June 1, 2018⁷, the Location also is a Dispatch Zone.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods commencing on or after June 1, 2018⁷, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart CIP Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Major Transmission Outage is a major transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b)(v) of Market Rule 1.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principals imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1, to meet the Installed Capacity Requirement.

Maximum Consumption Limit is the maximum amount, in MW, available from the Dispatchable Asset Related Demand for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data except that a Self-Scheduled Dispatchable Asset Related Demand may modify its Minimum Consumption Limit on an hourly basis, as part of its Demand Bid, in order to indicate the desired level of Self-Scheduled MW.

Maximum Facility Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand of a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset, where the demand evaluated is established by adding actual metered demand and the output of all generators located behind the asset's end-use customer meter in the same time intervals.

Maximum Generation is the maximum generation output of a Real-Time Demand Response Asset comprised of Distributed Generation or the maximum generation output of a Demand Response Asset comprised of Distributed Generation.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset's peak load less its uninterruptible load. For assets that deliver reductions through the use of generation, the Maximum Interruptible Capacity is the difference between the generator's maximum possible output and its expected output when not providing demand reduction. For assets that deliver demand reduction and Net Supply, the Maximum Interruptible Capacity is the asset's peak load plus Maximum Net Supply as measured at the Retail Delivery Point.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, of a Demand Response Asset, Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

Maximum Net Supply is an estimate of the maximum hourly Net Supply for a Demand Response Asset as measured from the Demand Response Asset's Retail Delivery Point.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time a 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 Demand Resources comprised of an aggregation of

measures with varied Measure 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 Value of the Demand Resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the Demand Reduction Value for an Existing Demand Resource is not overstated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1, which includes Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by a Demand Resource supplier as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by Demand Resource suppliers during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MG TSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a

start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MG TSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Minimum Consumption Limit is the minimum amount, in MW, available from a Dispatchable Asset Related Demand that is not available for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data.

Minimum Down Time is the number of hours that must elapse after a Generator Asset has been released for shutdown at or below its Economic Minimum Limit before the Generator Asset can be brought online and be released for dispatch at its Economic Minimum Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources to operate at or below Economic Minimum Limit, in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit.

Minimum Time Between Reductions is the minimum number of hours that a Market Participant requires between the time the Demand Response Resource receives a Dispatch Instruction from the ISO to not reduce demand and the time the Demand Response Resource receives a Dispatch Instruction from the ISO to reduce demand.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Variance means a Demand Resource's actual monthly Capacity Value established pursuant to Section III.13.7.1.5.1 of Market Rule 1, minus the Demand Resource's final Capacity Supply Obligation for the month.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

Net Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

Net Supply is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.

Net Supply Limit is the estimated portion of the offered Maximum Reduction of a Demand Response Resource that would be provided through Net Supply. The Net Supply Limit is calculated by multiplying the offered Maximum Reduction of the Demand Response Resource by the ratio of total Net Supply to total demand reduction performance from the prior like Seasonal DR Audit of the Demand Response Assets that are mapped to the Demand Response Resource for the month.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Required is the amount of additional capacity required to meet the Installed Capacity Requirement or a Capacity Zone's Local Sourcing Requirement, as described in Section III.13.2.8.1.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.2 of Market Rule 1.

New Demand Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III 13.1.4.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Resource.

New Demand Resource Show of Interest Form is described in Section III.13.1.4.2 of Market Rule 1.

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but does not have a winter audit value and a summer audit value.

New Demand Response Asset Audit is an audit of a New Demand Response Asset performed pursuant to Section III.13.6.1.5.4.8.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Nodal Amount is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a generating unit that must be paid to Market Participants with an Ownership Share in the unit for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the generating unit is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.3.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an increment of an Existing Capacity Resource that is treated as a New Capacity Resource in the Forward Capacity Auction and that has not been declared commercial and has not had its capacity rating verified by the ISO.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. “Non-Incumbent Transmission

Developer' also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Intermittent Settlement Only Resource is a Settlement Only Resource that is not an Intermittent Power Resource.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-Price Retirement Request is a binding request to retire the entire capacity of a Generating Capacity Resource as described in Section III.13.1.2.3.1.5.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2018⁷, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2018⁷; Demand Response Resources for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is, for a generating Resource, a Supply Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR available from the Resource from an off-line state, and, for a Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched, is a Demand Bid or Demand Reduction Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR or TMSR available from the Resource.

Offered CLAIM30 is a Supply Offer, Demand Bid or Demand Reduction Offer value between 0 and the CLAIM30 of a Resource that represents the amount of TMOR available from an off-line generating Resource, or Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched.

Offered Full Reduction Time is the value calculated pursuant to Section III.13.6.1.5.4.6.

On-Peak Demand Resource is a type of Demand Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a

comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement.

With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a generating unit asset or Load Asset, where such unit or load is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The "Phase II Transfer Capability" is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state

entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Resource participate in the Forward Capacity Market, as described in Section III.13.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b)(iii) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(c)(iii) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E1.8 for Capacity Commitment Periods commencing prior to June 1, 201~~87~~, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 201~~87~~.

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Real-Time Demand Response Resources of such hours.

Real-Time Demand Response Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of

values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Demand Response Resource.

Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

Real-Time Emergency Generation Resource is Distributed Generation whose federal, state and/or local air quality permits, rules or regulations limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving

a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(ii) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(c)(ii) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b)(i) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(c)(i) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b)(iv) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(c)(iv) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Price Response Program is the program described in Appendix E to Market Rule 1.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were

PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may

submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, for Capacity Commitment Periods commencing on or after June 1, 2018⁷, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTTA holder that sells, assigns or transfers its rights under its MGTTA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in \$/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource

or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2018⁷, a Demand Response Resource. For purposes of providing Regulation, Resource means a generating unit, a Dispatchable Asset Related Demand, a Demand Response Regulation Resource or an Alternative Technology Regulation Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission’s corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

Seasonal Peak Demand Resource is a type of Demand Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Self-Schedule is the action of a Market Participant in committing or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing or scheduling a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been scheduled or dispatched by the ISO to provide the Energy. For a Dispatchable Asset Related Demand, Self-Schedule is the action of a Market Participant in committing or scheduling a Dispatchable Asset Related Demand to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the Dispatchable Asset Related Demand would have been scheduled or dispatched by the ISO to consume Energy. Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to: (i) a Generator Asset's Economic Minimum Limit; (ii) a Dispatchable Asset Related Demand's Minimum Consumption Limit.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock; (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks,

franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of (1) a generating Resource that can be converted fully into energy within ten minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of (1) a generating Resource that is electrically synchronized to the New England Transmission System that can be converted fully into energy within ten minutes from the request of the ISO; (2) a Dispatchable Asset Related Demand pump that is electrically synchronized to the New England Transmission System that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO for which none of the associated Demand Response Assets have a generator whose output can be controlled located behind the Retail Delivery Point other than emergency generators that cannot operate electrically synchronized to the New England Transmission System.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) means the reserve capability of (1) a generating Resource that can be converted fully into energy within thirty minutes from the request of the ISO (2) a

Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within thirty minutes from the request of the ISO.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart O&M Payment is the annual compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than \$0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1

III.8 Demand Response Baselines

III.8A Demand Response Baselines Before June 1, 2018

Section III.8.A shall govern Demand Response Baselines calculated for Capacity Commitment Periods commencing prior to June 1, 201~~8~~⁷.

A Demand Response Baseline is calculated for any Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that requires a baseline on a daily basis using five-minute meter data.

8A.1 Establishing the Initial Demand Response Baseline

The Demand Response Baseline for a new Real-Time Demand Response Asset or Real-Time Emergency Generation Asset (an asset with no previously computed Demand Response Baseline) shall be the simple average of meter data for the asset for ~~each-the same~~ five-minute interval from the ~~initial ten non-Demand Response Holiday weekdays. The initial ten non-Demand Response Holiday weekdays of meter data used to establish the Demand Response Baseline shall consist of the first ten-10~~ consecutive ~~non-Demand Response Holiday~~ weekdays (~~excluding Demand Response Holidays~~) with a complete set of interval meter data. A Market Participant may not submit Demand Reduction Offers until the month following the initial establishment of a Demand Response Baseline for an asset.

If two or more existing Real-Time Demand Response Assets (assets registered with the ISO with previously computed Demand Response Baselines) located at or behind the same retail delivery point are consolidated into one Real-Time Demand Response Asset located at the retail delivery point, or a significant change in load, generation, or reported meter data at an existing Real-Time Demand Response Asset or Real-Time Emergency Generation Asset occurs, a new initial Demand Response Baseline must be established for the asset.

8A.2 Establishing the Demand Response Baseline ~~for the Next Day~~

Prior to June 1, 2017, if, for a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

- (a) the asset has been dispatched or audited in the present day pursuant to Section III.13, or;
- (b) the Demand Reduction Offer associated with the asset is eligible in the present Operating Day for payments pursuant to Section III.E1.9, or;
- (c) the present day is a Demand Response Holiday, Saturday or Sunday, then:

the asset's Demand Response Baseline, in each five-minute interval, for the next day is equal to the Demand Response Baseline, in the same five-minute interval from the present day.

Beginning June 1, 2017, for a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline, the asset's Demand Response Baseline in each five-minute interval of each day shall be the simple average of meter data for the same five-minute interval from 10 weekdays (excluding Demand Response Holidays), chosen from the previous 30 weekdays (excluding Demand Response Holidays) pursuant to Section III.8A.3.

8A.3 Determining ~~the if-Meter Data From the Present Day is~~ Used in the Demand Response Baseline ~~for the Next Day.~~

~~Prior to June 1, 2017, if,~~ for a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

- ~~(a) (i)~~ (i) the present day is not a Demand Response Holiday, Saturday or Sunday, ~~and;~~ the asset has not been dispatched or audited in the present day pursuant to Section III.13, ~~and;~~ the Demand Reduction Offer associated with the asset is not eligible in any hour of the present day for payments pursuant to Section III.E1.9; ~~or;~~
- ~~(b) (ii)~~ (ii) the present day is not a Demand Response Holiday, Saturday or Sunday and more than seven of the prior 10 ~~non-Demand Response Holiday~~ weekdays (excluding Demand Response Holidays) have established a Demand Response Baseline determined pursuant to Section III.8A.2; then:

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the asset's Demand Response Baseline, in each five-minute interval, for the next day is calculated as the sum of 0.9 times the asset's Demand Response Baseline established for the present day in the same five-minute interval and 0.1 times the asset's meter data in the same five-minute interval from the present day.

Beginning June 1, 2017, for each Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline, the asset's Demand Response Baseline in each five-minute interval of each day shall be the simple average of meter data for the same five-minute interval from 10 weekdays (excluding Demand Response Holidays), chosen from the previous 30 weekdays (excluding Demand Response Holidays) as follows.

- (a) Where there are at least 10 days that meet the following criteria:
- (i) the asset has not been dispatched or audited pursuant to Section III.13; and
 - (ii) the Demand Reduction Offer associated with the asset was not eligible in the Operating Day for payments pursuant to Section III.E1.9; and
 - (iii) if the asset is on a forced or scheduled curtailment, actual meter data values have not been submitted for any interval of the day pursuant to Section III.8A.5.3;
- then meter data from the 10 most recent such days will be used in the Demand Response Baseline calculation.
- (b) Where there are less than 10 days that meet the criteria in (a), meter data from all days that meet the criteria in (a) will be used; in addition, until 10 days are identified, meter data will be used from the most recent days that do not meet one or more of the criteria in (a).

8A.4 Baseline Adjustment

8A.4.1 Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets Without Generation or From Real-Time Emergency Generation Assets Without Additional Generation

For each day the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between the asset's actual metered demand and its Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load.

8A.4.2 Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets with Generation or From Real-Time Emergency Generation Assets With Additional Generation

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset, the ISO will calculate an adjustment factor

equal to the average difference (MW) between the sum of the asset's actual metered demand and the output of all generators, or for Real-Time Emergency Generation Assets all additional generators, located behind the asset's end-use customer meter in the same time intervals and the asset's Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Facility Load.

8A.4.3 Baseline Adjustment for Real-Time Demand Reductions Produced By Directly Metered Generation

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset that is comprised of a Distributed Generation asset located behind the end-use customer meter of an individual end-use customer facility, the asset's Demand Response Baseline shall not be subject to the baseline adjustment.

8A.4.4 Baseline Adjustment for Real-Time Demand Reductions Produced by a Real-Time Demand Response Asset Located At a Retail Delivery Point Where There Are No Other Real-Time Demand Response Assets At or Behind that Retail Delivery Point

For a Real-Time Demand Response Asset located at a retail delivery point with no other Real-Time Demand Response Assets at or behind the same retail delivery point, the metered output of any Real-Time Emergency Generation Assets in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline. Each generator located behind an individual end-use customer's retail delivery point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between (1) the sum of the asset's actual metered demand as measured at the asset's retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the asset's retail delivery point in the same time intervals, and (2) the asset's Demand Response Baseline in the intervals during the

two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, for assets that cannot produce net supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Facility Load. For assets that can produce net supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than the maximum amount (MW) that the asset is allowed to push back into the electric system per the applicable generator interconnection agreement (where the amount (MW) pushed back into the electric system is a negative value) and shall not exceed the asset's Maximum Facility Load.

The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval minus the sum of the metered demand measured at the retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of any Real-Time Emergency Generation Assets is greater than its adjusted Demand Response Baseline.

8A.5 Establishing the Demand Response Baseline for a Day with a Scheduled or a Forced Curtailment

8A.5.1 Notification of Forced and Scheduled Curtailments

A Market Participant, with a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset for which a Demand Response Baseline measured at the retail delivery point is utilized, may notify the ISO of a forced curtailment for any reductions in demand that occur as a result of actions outside the control of the Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that is subject to the forced curtailment.

A Market Participant may notify the ISO of a scheduled curtailment at least seven calendar days before the start of any reductions in a Real-Time Demand Response Asset's demand or a Real-Time Emergency Generation Asset's demand where a Demand Response Baseline measured at the retail delivery point is utilized, that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Real-Time Demand Response Assets or Real-

Time Emergency Generation Assets with a Maximum Interruptible Capacity of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The length of a scheduled curtailment must be a minimum of a single calendar day and may not exceed a total of 14 calendar days per Capacity Commitment Period.

8A.5.2 Submitting Meter Data Values for Days with Forced or Scheduled Curtailments

For each calendar day on which a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset where a Demand Response Baseline measured at the retail delivery point is utilized, is on a forced or scheduled curtailment, the asset's Demand Designated Entity shall submit to the ISO meter data values equal to the unadjusted baseline calculated for the first day of the forced or scheduled curtailment for all intervals excluding those in which the Real-Time Demand Response Resource with which the Real-Time Demand Response Asset is associated, or the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13, and excluding those in which a Demand Reduction Offer associated with the Real-Time Demand Response Asset had cleared day-ahead or became eligible in real-time pursuant to Section III.E1 on a day with an unanticipated forced curtailment.

8A.5.3 Performance Assessment for Days with Forced or Scheduled Curtailments

To assess the performance of Real-Time Demand Response Assets and Real-Time Emergency Generation Assets that are on a forced or scheduled curtailment, actual meter data values shall be submitted to the ISO for intervals during which the Real-Time Demand Response Resource with which the Real-Time Demand Response Asset is associated, or the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13, and intervals in which a Demand Reduction Offer associated with the Real-Time Demand Response Asset was cleared day-ahead or became eligible during the Operating Day pursuant to Section III.E1 on a day with an unanticipated forced curtailment.

III.8B Demand Response Baselines Beginning June 1, 2018

Section III.8B shall govern Demand Response Baselines calculated for Capacity Commitment Periods commencing on or after June 1, 2018.

A Demand Response Baseline is calculated in five-minute intervals for each Demand Response Asset and each Real-Time Emergency Generation Asset that is metered at the Retail Delivery Point for the following three day types:

- (a) weekdays (~~Monday-Friday~~ that are non-excluding Demand Response Holidays);
- (b) Saturdays; and;
- (c) Sundays (~~including and~~ Demand Response Holidays).

8B.1 Demand Response Baseline Calculations

If a Demand Response Asset's metered demand represents Net Supply in an interval, that Net Supply will be used in the Demand Response Baseline calculations for that interval pursuant to Sections III.8B.2, III.8B.3, and III.8B.4.

8B.1.1 Demand Response Baseline Real-Time Emergency Generation Asset Adjustment

To the extent a Real-Time Emergency Generation Asset is located at the same Retail Delivery Point as a Demand Response Asset, the metered output of the Real-Time Emergency Generation Asset, in each five-minute interval, shall be added to the metered demand measured at the Retail Delivery Point in the same intervals for purposes of determining the Demand Response Asset's Demand Response Baseline.

8B.2 Establishing an Initial Demand Response Baseline and Resetting a Baseline

An initial Demand Response Baseline will be established for a Demand Response Asset with no previously computed Demand Response Baseline, and for a Real-Time Emergency Generation Asset with no previously computed Demand Response Baseline when a Demand Response Baseline measured at the Retail Delivery Point is utilized for the asset. A Demand Response Baseline will be reset using the initial baseline calculation methodology set forth below when a significant change in load, generation, or reported meter data at an existing Demand Response Asset or Real-Time Emergency Generation Asset occurs.

For a weekday (excluding Demand Response Holidays) day type, the initial Demand Response Baseline, or a reset of a Demand Response Baseline, for each five-minute interval shall be the simple average of metered demand data for the asset for the same each five-minute interval, subject to the conditions in Section III.8B.1, from the initial 10 days of the same day type. The initial 10 days of meter data used to establish the Demand Response Baseline shall consist of the first 10 consecutive days of the same day type weekdays (excluding Demand Response Holidays) with a complete set of interval meter data.

For a Saturday day type, the initial Demand Response Baseline, or a reset of a Demand Response Baseline, for each five-minute interval shall be the simple average of meter data for the asset for the same five-minute interval, subject to the conditions in Section III.8B.1, from the first five consecutive Saturdays with a complete set of interval meter data.

For a Sunday and Demand Response Holiday day type, the initial Demand Response Baseline, or a reset of a Demand Response Baseline, for each five-minute interval shall be the simple average of meter data for the asset for the same five-minute interval, subject to the conditions in Section III.8B.1, from the first five consecutive Sundays and Demand Response Holidays with a complete set of interval meter data.

A Market Participant may not submit Demand Reduction Offers for a Demand Response Resource for a given day type in a given until 1) the month following unless the establishment of the initial baseline for that day type for by at least one Demand Response Asset mapped to the Demand Response Resource; provided that the initial baseline was established prior to the last at least seven calendar days prior to week of the first day of that month or, 2) two months following the establishment of the initial baselines for at least one Demand Response Asset mapped to the Demand Response Resource. This condition applies when establishing an initial Demand Response Baseline but not when resetting a Demand Response Baseline.

8B.3 Determining the Meter Data Used to Calculate the Demand Response Baseline for a Weekday (excluding Demand Response Holidays) Day Type Establishing a Demand Response Baseline for the Next Day

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For a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for weekdays (excluding Demand Response Holidays), the asset's weekday (excluding Demand Response Holiday) Demand Response Baseline in each five-minute interval shall be

the simple average of meter data for the same five-minute interval from 10 weekdays (excluding Demand Response Holidays), chosen from the previous 30 weekdays (excluding Demand Response Holidays) as follows.

- (a) If at least 10 of the previous 30 weekdays (excluding Demand Response Holidays) meet the following criteria, then the 10 most recent such days will be used: (i) the resource associated with the asset has not received a Dispatch Instruction for an amount greater than 0 MW; and (ii) if the asset is on a forced or scheduled curtailment, actual meter data values have not been submitted for any interval of the day pursuant to Section III.8B.6.3.
- (b) If less than 10 of the previous 30 weekdays (excluding Demand Response Holidays) meet the criteria in (a), then, in addition to those days that meet the criteria in (a), the most recent weekday (excluding Demand Response Holidays) that does not meet one or more of the criteria in (a) will be used, until 10 days are identified.

~~If, for a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for a day type and the asset is associated with a Demand Response Resource that has been dispatched or audited in the present day pursuant to Section III.E2.5 or Section III.13, the Demand Response Baseline of the Demand Response Asset or Real-Time Emergency Generation Asset, in each five-minute interval, for the next day of the same day type is equal to the Demand Response Baseline of that Demand Response Asset or Real-Time Emergency Generation Asset, in the same five-minute interval from the present day.~~

8B.4 Determining the if Meter Data from the Present Day is Used to Calculate the Demand Response Baseline for a Saturday Day Type or a Sunday and Demand Response Holiday in the Demand Response Baseline for the Next Day of the Same Day Type

8B.4.1 Determining the Meter Data Used to Calculate the Demand Response Baseline for a Saturday Day Type

For a Saturday day type: For a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for Saturdays, the asset's Demand Response Baseline in each five-minute interval shall be the simple average of meter data for the same five-minute interval from five Saturdays, chosen from the previous 42 calendar days as follows.

- (a) If at least five Saturdays meet the following criteria, then the five most recent such days will be used: (i) the resource associated with the asset did not receive a Dispatch Instruction for an

amount greater than 0 MW; and (ii) if the asset is on a forced or scheduled curtailment, actual meter data values were not submitted for any interval of the day pursuant to Section III.8B.6.3.

(a)(b) If less than five Saturdays meet the criteria in (a), then, in addition to those days that meet the criteria in (a), the most recent Saturday that does not meet one or more of the criteria in (a) will be used, until five days are identified.

8B.4.2 Determining the Meter Data Used to Calculate the Demand Response Baseline for a Sunday and Demand Response Holiday Day Type

For a Sunday and Demand Response Holiday day type: For a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for Sundays and Demand Response Holidays, the asset's Sunday and Demand Response Holiday Demand Response Baseline in each five-minute interval shall be the simple average of meter data for the same five-minute interval from five Sundays and Demand Response Holidays, chosen from the previous 42 calendar days as follows.

(a) If at least five Sundays and Demand Response Holidays meet the following criteria, then the five most recent such days will be used: (i) the resource associated with the asset did not receive a Dispatch Instruction for an amount greater than 0 MW; and (ii) if the asset is on a forced or scheduled curtailment, actual meter data values were not submitted for any interval of the day pursuant to Section III.8B.6.3.

(a)(b) If less than five Sundays and Demand Response Holidays meet the criteria in (a), then, in addition to those days that meet the criteria in (a), the most recent Sunday or Demand Response Holiday that does not meet one or more of the criteria in (a) will be used, until five days are identified.

~~If, for a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for that day type, the Demand Response Resource or Real-Time Emergency Generation Resource to which the asset is associated has not been dispatched or audited in the present day pursuant to Section III.E2.5 or Section III.13, or more than seven of the prior 10 days of the same day type have a Demand Response Baseline determined pursuant to Section III.8B.3, then the Demand Response Baseline of the Demand Response Asset or Real-Time Emergency Generation Asset in each five-minute interval, for the next day of the same day type as the present day, is calculated as the sum of 0.9 times the Demand Response Baseline of that Demand Response Asset or Real-Time Emergency Generation Asset for the present day in the same five-minute interval and 0.1 times the~~

~~Demand Response Asset's or Real-Time Emergency Generation Asset's meter data, subject to the conditions in Section III.8B.1, in the same five-minute interval from the present day.~~

8B.5 Baseline Adjustment

The Demand Response Baseline for each Demand Response Asset and each Real-Time Emergency Generation Asset is updated approximately every quarter hour by an adjustment factor that is calculated in accordance with this Section III.8B.5, which may increase or decrease the baseline.

- (a) An adjustment factor is calculated if the resource with which the asset is associated is not in a period of dispatch (as defined by the resource's Dispatch Instruction including the Demand Response Resource Start-Up Time and Demand Response Resource Notification Time). The adjustment factor is calculated with real-time telemetry data in Real-Time and is calculated with revenue quality metering data for settlement purposes.
- (b) For an asset that is part of a resource that is not in a period of dispatch, the adjustment factor is calculated using five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the start of the quarter hour. For an asset that is part of a resource that has received a Dispatch Instruction, the adjustment factor is calculated using five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the start of the quarter hour before the Dispatch Instruction was issued. After completion of a dispatch, the adjustment factor for an asset will be calculated using the five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the start of the quarter hour before the Dispatch Instruction was issued, until sufficient time has elapsed to calculate the adjustment using post-dispatch interval data.
- (c) For a Demand Response Asset, the adjustment factor is equal to the average difference (MW) between the Demand Response Asset's telemetered or metered demand, which shall be adjusted pursuant to Section III.8B.1.1 (inclusive of any Net Supply), and its Demand Response Baseline during the three intervals. For a Real-Time Emergency Generation Asset the adjustment factor is equal to the average difference (MW) between the Real-Time Emergency Generation Asset's telemetered or metered demand and its Demand Response Baseline during the three intervals.
- (d) For Demand Response Assets that cannot produce Net Supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load. For Demand Response Assets that can produce Net Supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than the maximum amount (MW) that the asset is allowed to push back into the electric system per the applicable generator interconnection agreement (where the amount (MW) pushed back into the electric system is a negative value) and shall not exceed the asset's Maximum Facility Load.

8B.6 Establishing the Demand Response Baseline for a Day with a Scheduled or a Forced Curtailment

8B.6.1 Notification of Forced and Scheduled Curtailments

A Market Participant, with a Demand Response Asset or a Real-Time Emergency Generation Asset for which a Demand Response Baseline measured at the Retail Delivery Point is utilized, may notify the ISO of a forced curtailment for any reductions in demand that occur as a result of actions outside the control of the Demand Response Asset or Real-Time Emergency Generation Asset that is subject to the forced curtailment.

A Market Participant may notify the ISO of a scheduled curtailment at least seven calendar days before the start of any reductions in a Demand Response Asset's demand or a Real-Time Emergency Generation Asset's demand where a Demand Response Baseline measured at the Retail Delivery Point is utilized, that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Demand Response Assets or Real-Time Emergency Generation Assets with a Maximum Interruptible Capacity of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The length of a scheduled curtailment must be a minimum of a single calendar day and may not exceed a total of 14 calendar days per Capacity Commitment Period.

III.8B.6.2 Submitting Meter Data Values for Days with Forced or Scheduled Curtailments

For each calendar day on which a Demand Response Asset or a Real-Time Emergency Generation Asset, where a Demand Response Baseline measured at the Retail Delivery Point is utilized, is on a forced or scheduled curtailment pursuant to Section III.8B.6.1, the asset's Demand Designated Entity shall submit to the ISO meter data values equal to the unadjusted baseline for the day type, calculated on the first occurrence of that day type during the forced or scheduled curtailment, ~~for the first day of the forced or scheduled curtailment~~ for all intervals excluding those intervals in which:

- ~~(a) a Capacity Scarcity Condition existed in the Capacity Zone in which the Demand Response Asset is located.~~
- ~~(a) the Demand Response Resource with which the Demand Response Asset is associated was dispatched during the period of a Shortage Event as defined in Section III.13.7.1.1.1 for the Capacity Zone in which the resource is located.~~

- (b) the Demand Response Resource with which the Demand Response Asset is associated was dispatched in Real-Time pursuant to Section III.E2 on the first day of an unanticipated forced curtailment, or
- (c) the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13.

III.8B.6.3 Performance Assessment for Days with Forced or Scheduled Curtailments

To assess the performance of Demand Response Assets and Real-Time Emergency Generation Assets that are on a forced or scheduled curtailment, actual meter data values shall be submitted to the ISO for intervals during which:

- (a) ~~a Capacity Scarcity Condition existed in the Capacity Zone in which the Demand Response Asset is located the Demand Response Resource with which the Demand Response Asset is associated was dispatched during the period of a Shortage Event as defined in Section III.13.7.1.1.1 for the Capacity Zone in which the Resource is located,~~
- (b) the Demand Response Resource with which the Demand Response Asset is associated was dispatched in Real-Time pursuant to Section III.E2 on the first day of an unanticipated forced curtailment, or
- (c) the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13.

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (Section III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section III.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Resource, New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the FCM Deposit.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1.

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than \$200 per kilowatt of the whole resource's summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than \$100 per kilowatt of the whole resource's summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The \$100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.

The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output greater than 2 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, but less than or equal to the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than \$200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff

(or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section does not cause the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement, the Project Sponsor must submit a New Capacity Qualification Package but is not required to submit a New Capacity Show of Interest Form for the incremental amount by the New Capacity Qualification Deadline. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.3 causes the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement or MW amount approved pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), the Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than \$200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.1.5. Treatment of Resources that are Partially New and Partially Existing.

For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.1.3 or Section III.13.1.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline. A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

III.13.1.1.1.7 Renewable Technology Resources.

To participate in the Forward Capacity Market as a Renewable Technology Resource, a Generating Capacity Resource or an On-Peak Demand Resource (including every asset that is part of the On-Peak Demand Resource) must satisfy the following requirements:

- (a) receive an out-of-market revenue source supported by a state- or federally-regulated rate, charge or other regulated cost recovery mechanism;
- (b) qualify as a renewable or alternative energy generating resource under any New England state's mandated (either by statute or regulation) renewable or alternative energy portfolio standards as

in effect on January 1, 2014, or, in states without a standard, qualify under that state's renewable energy goals as a renewable resource (either by statute or regulation) as in effect on January 1, 2014. The resource must qualify as a renewable or alternative energy generating resource in the state in which it is geographically located;

- (c) participate in a Forward Capacity Auction for a Capacity Commitment Period beginning on or after June 1, 2018 as a New Generating Capacity Resource or New Demand Resource pursuant to Section III.13.1.1, and;
- (d) has been designated for treatment as a Renewable Technology Resource pursuant to Section III.13.1.1.2.9.

An Export De-List Bid or Administrative Export De-List Bid may not be submitted for Generating Capacity Resources that assumed a Capacity Supply Obligation by participating in a Forward Capacity Auction as a Renewable Technology Resource.

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.

For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also submit to the ISO, or in the case of an Import Capacity Resource seeking to qualify with an Elective Transmission Upgrade be associated with, an Interconnection Request under Schedules 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the interconnection procedures described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the FCM Deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be

irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, Material Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23, or Section 4.4 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein or the New Capacity Show of Interest Form shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor's contact information; the Project Sponsor's ISO customer status; the project's expected Commercial Operation date; the project address or location, and if relevant, asset identification number; the status of the project under the interconnection procedures described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project's equipment configuration, including a

description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff. In the case of a resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource that is supported by an Internal Elective Transmission Upgrade, all Queue Positions associated with the project must be submitted in the New Capacity Show of Interest Form. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period pursuant to Section III.13.1.1.2.2.1.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must achieve, prior to the close of the New Capacity Show of Interest Submission Window, control of the project site for the duration of the relevant Capacity Commitment Period, which shall be as defined in Section 4.1 of Schedule 22, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits.** In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing.** In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders.** In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2.2(d) and that accounts for more than five percent of the total project cost. For an Import Capacity Resource associated with an Elective Transmission Upgrade that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, major components shall also include, to the extent applicable, transmission facilities and associated substation equipment.

(d) **Substantial Site Construction.** In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery.** In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing.** In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (d) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent Commercial Operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning.** In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation.** In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. Offer Information.

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity at or above the Economic Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity Resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.1.2.2.4. Capacity Commitment Period Election.

In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional

and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity.

In addition to the information described elsewhere in this Section III.13.1.1.2.2:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource and Intermittent Settlement Only Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

- (a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);
- (b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource or the Intermittent Settlement Only Resource.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a Material Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23 and Section 4.4 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service in a manner that meets the Capacity

Capability Interconnection Standard in accordance with the provisions in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource's Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) or Elective Transmission Upgrade Interconnection Customer as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s) or Elective Transmission Upgrade Interconnection Customer, as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the

Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

(g) New Generating Capacity Resources, or portions thereof, shall not be considered to have met their Capacity Supply Obligation for the purposes of this Forward Capacity Market and shall not receive compensation if any upgrades to be completed by the Project Sponsor required to remove overlapping interconnection impacts as identified in (f) have not been completed, including, any upgrades identified in a restudy pursuant to Section 3.2.1.3 of Schedule 22, Section 1.7.1.3 of Schedule 23, or Section 3.2.1.3 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff in time for the Capacity Commitment Period unless the Capacity Supply Obligation is appropriately covered.

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource's New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

- (a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;
- (b) whether the critical path schedule includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule are reasonable and likely to be met;
- (d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and
- (e) whether, in the case of an Intermittent Power Resource or Intermittent Settlement Only Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified

Capacity for such a resource shall be equal to the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. [Reserved.]

III.13.1.1.2.7. Opportunity to Consult with Project Sponsor.

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

- (a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;
- (b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource's New Capacity Qualification Package was not accepted;
- (c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);
- (d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource's summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;
- (e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Resource; (ii) for the notification to a Conditional Qualified New Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Resource, the Queue Position of the Conditional Qualified New Resource; and
- (f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal

Market Monitor's determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.1.2.9 Renewable Technology Resource Election.

A Project Sponsor or Market Participant electing Renewable Technology Resource treatment for the FCA Qualified Capacity of a New Generating Capacity Resource or New Demand Resource shall submit a Renewable Technology Resource election form no later than five Business Days after the date on which the ISO provides qualification determination notifications pursuant to Section III.13.1.1.2.8 or Section III.13.1.4.2.5.3. Only the portion of the FCA Qualified Capacity of the resource that meets the requirements of Section III.13.1.1.1.7 is eligible for treatment as a Renewable Technology Resource.

Renewable Technology Resource elections may not be modified or withdrawn after the deadline for submission of the Renewable Technology Resource election form.

The submission of a Renewable Technology Resource election that satisfies the requirements of Section III.13.1.1.1.7 will invalidate a prior multi-year Capacity Supply Obligation and Capacity Clearing Price election for the same resource made pursuant to Section III.13.1.4.2.2.5 or Section III.13.1.1.2.2.4 for a Forward Capacity Auction.

III.13.1.1.2.10 Determination of Renewable Technology Resource Qualified Capacity.

- (a) If the total FCA Qualified Capacity of Renewable Technology Resources exceeds the cap specified in subsections (b), (c) and (d) the qualified capacity value of each resource shall be prorated by the ratio of the cap divided by the total FCA Qualified Capacity. The ISO shall notify the Project Sponsor or Market Participant, as applicable, of the Qualified Capacity value of its resource no more than three Business Days after the deadline for submitting Renewable Technology Resource elections.
- (b) The cap for the Capacity Commitment Period beginning on June 1, 2018 is 200 MW.
- (c) The cap for the Capacity Commitment Period beginning on June 1, 2019 is 400 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior Capacity Commitment Period.

(d) The cap for each Capacity Commitment Period beginning on or after June 1, 2020 is 600 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior two Capacity Commitment Periods.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Resource or Existing Demand Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each

year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that

is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006 summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be established pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e).

(b) The Intermittent Power Resource's or Intermittent Settlement Only Resource's summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.

(a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in each of the previous winter periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.

(b) The Intermittent Power Resource's and Intermittent Settlement Only Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2(a).

(c) The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity

Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the two treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource's summer Qualified Capacity set to the most recent

summer Seasonal Claimed Capability as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) [Reserved.]

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.3(a) but not the requirements of Section III.13.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only

Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, except as provided for in Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.5.2. An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section

III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

The Dynamic De-List Bid Threshold for a Forward Capacity Auction is \$5.50/kW-month. The Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders.

III.13.1.2.3.1.1. Static De-List Bids.

A Lead Market Participant with an Existing Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation for that resource, or a portion thereof, at prices at or above the Dynamic De-List Bid Threshold during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs). The curve may in no case increase the quantity offered as the

price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Lead Market Participant must notify the ISO if the Existing Capacity Resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests).

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, a Lead Market Participant that submitted a Static De-List Bid may: (a) lower the price of any price-quantity pair of a Static De-List Bid, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or; (b) withdraw any price-quantity pair of a Static De-List Bid.

III.13.1.2.3.1.2. Permanent De-List Bids.

A Lead Market Participant with an Existing Capacity Resource seeking to specify a price below which it would not accept a Capacity Supply Obligation permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource's full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids at or above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource, an Intermittent Settlement Only Resource or a Renewable Technology Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids at or above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource, an Intermittent Settlement Only Resource or a Renewable Technology Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-

List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity Commitment Period. Administrative Export De-List Bids shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.

A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request submitted in accordance with the timing requirements of Section III.13.1.2.3.1.5.2 supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.

The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a Permanent De-List Bid for which an Internal Market Monitor-determined price has been established pursuant to Section III.13.1.2.3.2.1.1.1, a Non-Price Retirement Request may be submitted for the affected portion of the bid within 14 days after the issuance by the ISO of the qualification determination notification or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.

III.13.1.2.3.1.5.3. Reliability Review of Non-Price Retirement Requests.

The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request

will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

III.13.1.2.3.1.5.4. Obligation to Retire.

A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5.3(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.

III.13.1.2.3.1.6. Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. Internal Market Monitor Review.

The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

- (i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.
- (ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive de-listing of each individual asset in preferred de-list order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of bids as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The bids of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid as described in Section III.13.1.2.3.2.1.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Capacity Resources.

The Internal Market Monitor shall review bids for Existing Capacity Resources as follows.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids at or Above the Dynamic De-List Bid Threshold, and Permanent De-List Bids at or Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid, each Export Bid at or above the Dynamic De-List Bid Threshold, and each Permanent De-List Bid at or above the Dynamic De-List Bid

Threshold to determine whether the bid is consistent with: (1) the Existing Capacity Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); (3) reasonable risk premium assumptions (as determined pursuant to Section III.13.1.2.3.2.1.4); and (4) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). Sufficient documentation and information about each of these bid components must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments and risk premiums, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate. The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

III.13.1.2.3.2.1.1.1. Review of Permanent De-List Bids and Export Bids.

If the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that a Permanent De-List Bid or an Export Bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid. If an Internal Market Monitor-determined price is established for a Permanent De-List Bid or an Export Bid, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the Internal

Market Monitor-determined price based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor.

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.

If the Internal Market Monitor determines, after due consideration and consultation with a Lead Market Participant, that a Static De-List Bid is not consistent with a resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid that is consistent with its determination of the foregoing.

If an Internal Market Monitor-determined price is established for a bid, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission described in Section III.13.8.1(a) shall include an explanation of the Internal Market Monitor-determined price based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor.

III.13.1.2.3.2.1.2. Net Going Forward Costs.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid, Export Bid at or above the Dynamic De-List Bid Threshold, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net going forward costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. A Static De-List Bid, Export Bid at or above the Dynamic De-List Bid Threshold, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing Capacity Resource's net going forward costs based on a review of the data submitted in the following formula. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{[GFC - (IMR - PER)] \times InfIndex}{(CQ_{Summer, kw}) \times (12, months)}$$

Where:

GFC = annual going forward costs, in dollars. These are costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

$CQ_{Summer, kW}$ = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid), this value shall be calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and

maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be \$0.00. As soon as practicable, the resource's total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected

InfIndex = inflation index. $\text{infIndex} = (1 + i)^4$

Where: "i" is the most recent reported 4- Year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid, Export Bid at or above the Dynamic De-List Bid Threshold, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.13.1.2.3.2.1.4. Risk Premium.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid, Export Bid at or above the Dynamic De-List Bid Threshold, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide

documentation separately detailing any risk premium included in the bid. This documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.13.1.2.3.2.1.2 may be included in this risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the Forward Capacity Market is consistent with the participant's corporate risk management practices.

III.13.1.2.3.2.1.5. Opportunity Costs.

To the extent that an Existing Capacity Resource submitting a Static De-List Bid, Export Bid at or above the Dynamic De-List Bid Threshold, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, expected Capacity Performance Payments, or risk premium components of the bid, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. Administrative Export De-List Bids.

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

Age of Existing Resource (years)	Remaining Life (years)	Annual Rate of Capital Cost Recovery
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{\text{Cost Of Capital}}{(1 - (1 + \text{CostOfCapital})^{-\text{RemainingLife}})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Qualification Determination Notification for Existing Capacity.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid and Export Bid concerning the result of the Internal Market Monitor's de-list bid review conducted pursuant to Section III.13.1.2.3.2. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external Demand Resource may not be an Existing Import Capacity Resource or a New Import Capacity Resource. External nodes shall be established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff.

An Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be included in the FCM (1) after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Forward Capacity Market qualification requirements or (2) after it has met the requirements of an Elective Transmission Upgrade with Long Lead Time Facility treatment pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff. An external node for such an Elective Transmission Upgrade will be modeled for participation in the Forward Capacity Market after the Import Capacity Resource meets the requirements to participate in the FCA. The Qualified Capacity of an Import Capacity Resource associated with an Elective Transmission Upgrade shall not exceed the Capacity Network Import Interconnection Service Interconnection Request. In order for an Elective Transmission Upgrade to maintain its Capacity Network Import Interconnection Service, an associated Import Capacity Resource must meet the Forward Capacity Market qualification requirements and offer into each Forward Capacity Auction. Otherwise, the Capacity Network Import Interconnection Service will revert to Network Import Interconnection Service for the portion of the Capacity Network Import Interconnection Service for which no Import Capacity Resource is offered into the Forward Capacity Auction and the Elective Transmission Upgrade's Interconnection Agreement will be revised. The provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election, shall apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade seeking to reestablish Capacity Network Import Interconnection Service if the threshold to be treated as a new resource in Section III.13.1.1.1.4 is met. If the threshold to be treated as a new increment in Section III.13.1.1.1.3 is met, only the increment will be eligible for the provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election.

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. Qualified Capacity for Existing Import Capacity Resources.

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3.A Qualification Process for Existing Import Capacity Resources that are not associated with an Elective Transmission Upgrade with Capacity Network Import Interconnection Service.

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

- (a) The Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.
- (b) The rationing election described in Section III.13.1.2.3.1 shall not apply.
- (c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3 for the duration of the contracts as listed.

For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3, no later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3.

Contract Description	MW	Contract End Date
NYPA: NY – NE: CMEEC	13.2	8/31/2025
NYPA: NY – NE: MMWEC	53.3	8/31/2025
NYPA: NY – NE: Pascoag	2.3	8/31/2025
NYPA: NY– NE: VELCO	15.3	8/31/2025
	84.1	
VJO: Highgate – NE	Up to 225	10/31/2016
VJO: Highgate – NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II – NE	Up to 110	10/31/2016

(d) In addition to the review described in Section III.13.1.2.3.2, the Internal Market Monitor shall review each bid from Existing Import Capacity Resources. A bid from an Existing Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.3.B. Qualification Process for Existing Import Capacity Resources that are associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service.

Existing Import Capacity Resources associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be subject to the same qualification process as Existing Generating Capacity Resources as described in Section III.13.1.2.3, except the Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and

the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

III.13.1.3.4. Definition of New Import Capacity Resource.

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

For each New Import Capacity Resource, the Project Sponsor submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the contract period including the entire Capacity Commitment Period, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the

import; or (iv) documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load. For each New Import Capacity Resource, the Project Sponsor must specify the interface over which the capacity will be imported. The Project Sponsor must indicate whether the import is associated with any investment in transmission that increases New England's import capability or is associated with an Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff. The Project Sponsor must submit a contract confirming its association with the Elective Transmission Upgrade Interconnection Customer and the ISO will confirm that relationship. If the import will be backed by a single new External Resource, the Project Sponsor submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Project Sponsor shall instead submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall apply in addition to the requirement that the Project Sponsor submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the Project Sponsor, the description must include a commitment that the External

Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the New Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Project Sponsor shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

If the New Import Capacity Resource will be backed by an external Control Area and the capacity will be imported over an Elective Transmission Upgrade and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall apply in addition to the requirement that the Project Sponsor submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource for the length of the multi-year contract.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.

The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) For imports crossing a single intervening Control Area, the Project Sponsor entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing. (2) For imports crossing more than one intervening Control Area, in addition to the

requirements above, the Project Sponsor entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load. (3) The Project Sponsor entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.13.1.3.5.4. Capacity Commitment Period Election.

The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall only apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request. All other New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction.

III.13.1.3.5.5. Initial Interconnection Analysis.

The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply unless the capacity will be imported over an Elective Transmission Upgrade pursuing Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.3.5.5.A. Cost Information.

The offer information described in Section III.13.1.1.2.2.3 and Section III.A.21.2 may be submitted in the form of a curve (up to five price-quantity pairs) associated with a specific New Import Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources.

In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from New Import Capacity Resources. An offer from a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.1.2.8, a Lead Market Participant with a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade) that submitted a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5 may: (a) lower the requested offer price of any price-quantity pair submitted to the ISO pursuant to Section III.13.1.1.2.2.3, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or (b) withdraw any price-quantity pair of a requested offer price.

III.13.1.3.5.8. Rationing Election.

New Import Capacity Resources are subject to rationing except New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request, which are eligible for the rationing election described in Section III.13.1.1.2.2.3(b).

III.13.1.4. Demand Resources.

III.13.1.4.1. Demand Resources.

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with ~~an early~~ Commercial Operation Date before June 1, 2018, or a Demand Response Capacity Resource that cleared in the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period, shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2018⁸⁷. No resource shall be permitted to participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life. Demand Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Resource. Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market Participant for a resource shall include the Enrolling Participant for a Demand Resource.

III.13.1.4.1.1. Existing Demand Resources.

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that

Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.

III.13.1.4.1.2. New Demand Resources.

A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.

For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources

For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for

participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.3. Special Provisions for Real-Time Emergency Generation Resources.

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.4.2. Show of Interest Form for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand

Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor's New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. Qualification Package for Existing Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. Qualification Package for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1. [Reserved.]

III.13.1.4.2.2.2. Source of Funding.

The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3. Measurement and Verification Plan.

For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4. Customer Acquisition Plan.

A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1. Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.

For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.2.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete

III.13.1.4.2.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor's ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor's program to deliver capacity to meet the Demand Resource Project Sponsor's Forward Capacity Auction obligations, and must include each customer's projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor's ability to fulfill its obligation by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource

Project Sponsor shall be subject to the ISO's critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. Capacity Commitment Period Election.

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.2.5.

III.13.1.4.2.2.6. Rationing Election.

The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form.

A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. Offers From New Demand Resources.

All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

III.13.1.4.2.5. Notification of Qualification for Demand Resources.

III.13.1.4.2.5.1. Evaluation of Demand Resource Qualification Materials.

The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

- (a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;
- (b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and

(e) whether the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.

For each Existing Demand Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type; and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located, and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. Notification of Qualification for New Demand Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.

For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource's summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.

For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.3. Measurement and Verification Applicable to All Demand Resources.

To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects in reducing demand coincident with Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours such that the reported monthly Demand Reduction Value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the Demand Resource project's Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor's total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor's total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Demand Resource Project Sponsors. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and

consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor's offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors shall maintain records of retail customers served including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly Demand Reduction Values. For Demand Resource projects targeting customer

facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor shall maintain records as described above for customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, or shall maintain records of aggregated Demand Reduction Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently delisted from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.

The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation, Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, ~~2017~~2018, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 201~~8~~7, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity

Commitment Periods commencing on or after June 1, 2018⁷, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2018⁷, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated using the Real-Time Emergency Generation Asset's Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the Retail Delivery Point, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated using the Real-Time Emergency Generations Asset's Average Hourly Load Reduction.

For Capacity Commitment Periods commencing before June 1, 2018⁷, the output of the generators comprising a Real-Time Emergency Generation Asset must be directly metered and reported to the ISO as a single set of interval meter data, provided that if there is no other Real-Time Emergency Generation Asset, Real-Time Demand Response Asset or other generator whose output can be controlled at the same facility, the Market Participant may instead meter the Real-Time Emergency Generation Asset at the retail delivery point. Meter data associated with the Real-Time Emergency Generation Asset shall be recorded and reported by the Market Participant to the ISO in Real-Time at an interval of five minutes.

For Capacity Commitment Periods commencing before June 1, 2018⁷, the output of generators comprising a Real-Time Demand Response Asset located behind the retail delivery point must be directly metered and reported to the ISO in Real-Time as a single set of interval meter data at an interval of five-minutes.

III.13.1.4.3.2.1. No Performance Data to Determine Demand Reduction Values.

Should a new Demand Resource, other than a Demand Response Capacity Resource, enter service at a time such that there is no performance data for June, July, August, December or January upon which to establish summer or winter seasonal Demand Reduction Values, and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, then the summer or winter seasonal Demand Reduction Values will be the simple average of its Demand Reduction Values for those months with a Capacity Supply Obligation.

For a new Demand Resource, other than a Demand Response Capacity Resource, that enters service outside of the summer DR Auditing Period or winter DR Auditing Period and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, the Demand Resource Commercial Operation Audit results shall be used in the determination of the summer or winter seasonal Demand Reduction Value.

III.13.1.4.3.3. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.13.1.4.3.4. Measurement and Verification Costs.

Costs associated with measurement and verification of the Demand Resource project shall be borne by the Demand Resource Project Sponsor. Demand Resource Project Sponsors submitting application materials and Measurement and Verification Documents for review during the Forward Capacity Auction qualification process shall be subject to the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.4.4. Dispatch of Active Demand Resources During Event Hours.

III.13.1.4.4.1. Notification of Demand Resource Forecast Peak Hours.

The ISO shall issue notice to Market Participants concerning Demand Resource Forecast Peak Hours on the day before the relevant Operating Day. The notice issued pursuant to this section is for informational purposes only and shall not constitute a Dispatch Instruction.

III.13.1.4.4.2. Dispatch of Demand Resources During Real-Time Demand Resource Dispatch Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Demand Response Resources to curtail and restore loads during Real-Time Demand Resource Dispatch Hours. Dispatch Instructions shall apply to Real-Time Demand Response Resources. The amount of Demand Resources dispatched for each Real-Time Demand Resource Dispatch Hour will be the amount that the ISO determines is necessary to meet the reserve deficiency. The ISO may issue Dispatch Instructions that reduce or increase the amount dispatched in each hour.

III.13.1.4.4.3. Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Emergency Generation Resources to curtail and restore loads during Real-Time Emergency Generation Event Hours. Dispatch Instructions shall apply to specific Real-Time Emergency Generation Resources. The amount of Real-Time Emergency Generation Resources dispatched for each Real-Time Emergency Generation Event Hour will be the amount the ISO determines is necessary to meet the reserve deficiency.

III.13.1.4.5. Selection of Active Demand Resources For Dispatch.

III.13.1.4.5.1. Management of Real-Time Demand Response Assets and Real-Time Demand Response Resources.

A Market Participant must manage its Real-Time Demand Response Assets that are registered as a component of a Real-Time Demand Response Resource as of the first of a month so that the Real-Time Demand Response Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Demand Response Assets cause, or potentially cause, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to restore the loads of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Demand Response Asset or to restore the load of a dispatched Real-Time Demand Response Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the restoration of that asset. Market Participants with Real-Time Demand Response Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Demand Response Resources consisting of an aggregation of more than one Real-Time Demand Response Asset shall report the load reduction and consumption, or generator output of the resource, to the ISO as the sum of the load reduction, consumption, or generator output of the individual assets making up that resource. Real-Time Demand Response Resources shall be assigned a unique resource identification number. The load reduction and consumption, or generator output of a Real-Time

Demand Response Resource is reported to the ISO as a single set of values. A Real-Time Demand Response Resource shall consist of one or more Real-Time Demand Response Assets that are located within the same Dispatch Zone.

III.13.1.4.5.2. Management of Real-Time Emergency Generation Assets and Real-Time Emergency Generation Resources.

A Market Participant must manage its Real-Time Emergency Generation Assets that are registered as a component of a Real-Time Emergency Generation Resource as of the first of a month so that the Real-Time Emergency Generation Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Emergency Generation Assets causes, or potentially causes, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to discontinue the output of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Emergency Generation Asset or to discontinue the output of a dispatched Real-Time Emergency Generation Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the discontinued output of that asset. Market Participants with Real-Time Emergency Generation Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Emergency Generation Resources consisting of an aggregation of more than one Real-Time Emergency Generation Asset shall report the generator output of the resource to the ISO as the sum of the generator outputs of the individual assets making up that resource. Real-Time Emergency Generation Resources shall be assigned a unique resource identification number. The generator output of a Real-Time Emergency Generation Resource is reported to the ISO as a single set of values. A Real-Time Emergency Generation Resource shall consist of one or more Real-Time Emergency Generation Assets that are located within the same Dispatch Zone.

III.13.1.4.5.3. [Reserved.]

III.13.1.4.6. Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at Dispatch Zones.

III.13.1.4.6.1. Establishment of 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 and dispatch of Demand Response Capacity Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources. Dispatch Zones shall not

change during a Capacity Commitment Period. 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. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.13.1.4.6.2. Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

III.13.1.4.6.2.1. Real-Time Demand Response Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Demand Response Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Demand Response Resource into one or more Real-Time Demand Response Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference, terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.6.2.2. Real-Time Emergency Generation Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Emergency Generation Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Emergency Generation Resource into one or more Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of

the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference, terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.7. [Reserved.]

III.13.1.4.8. [Reserved.]

III.13.1.4.9. Restrictions on Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Registration.

A Market Participant may not register and, if previously registered, must retire in accordance with Section III.13.1.4.9.1, a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of:

- (a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or
- (b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

III.13.1.4.9.1. Requirement for Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Retirement.

A Market Participant must retire a previously registered Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak

Demand Resource that is comprised of customers specified in subsections (a) or (b) of Section III.13.1.4.9 no later than 12 months from the date that the ISO receives notice that the relevant electric retail regulatory authority prohibits such customer's demand response to be bid into the ISO-administered markets or programs or May 31, 2013, whichever is later.

III.13.1.4.10. Providing Information On Demand Response Capacity, Real-Time Demand Response and Real-Time Emergency Generation Resources.

If requested by a Market Participant with a registered Load Asset, the ISO will provide the following information about end-use customers served by the Market Participant: (a) whether the end-use customer's facility is registered with the ISO as part of an asset and whether the asset is associated with a Demand Response Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource, and; (b) the load reduction capability of the asset, as specified in the ISO's asset registration system, to which the end-use customer's facility is registered.

III.13.1.4.11. Assignment of Demand Assets to a Demand Resource.

The following mapping provisions apply to Demand Resources other than Demand Response Capacity Resources, the mapping for which is addressed in Appendix E to Market Rule 1.

(a) When a demand asset can be mapped to more than one Demand Resource, any demand assets shall be mapped to a commercial Demand Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period, before being mapped to a non-commercial Demand Resource or non-commercial increment of a Demand Resource.

(b) A demand asset cannot be unmapped from a Demand Resource if, following the unmapping, the sum of the audit values of the remaining demand assets that are mapped to the Demand Resource would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides

qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.2.4.5.3. Offers composed of separate resources may not be modified or withdrawn after the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Resource, April through November where the summer resource is a Demand Resource) of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period (October through May where the summer resource is not a Demand Resource, December through March where the summer resource is a Demand Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource or Intermittent Settlement Only Resource. If the winter capacity of the offer composed of separate resources in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

- (d) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone.
- (e) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained.
- (f) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone.
- (g) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource.
- (h) A Renewable Technology Resource may only participate in an offer composed of separate resources if its FCA Qualified Capacity has not been prorated pursuant to Section III.13.1.1.2.10.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than five Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource's final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource's financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the FCM Deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing

Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c) and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity's Capacity Load Obligation in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that

export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

- (a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.
- (b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.
- (c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.
- (d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) If a Permanent De-List Bid at or above the Dynamic De-List Bid Threshold or a Static De-List Bid for which an Internal Market Monitor-determined price has not been established, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.13.1.9. Financial Assurance.

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Resources) and New Demand Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the FCM Deposit by the Project Sponsor for a New Generating Capacity Resource or New Demand Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Resource in the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the FCM Deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, financial assurance required prior to the auction pursuant to FAP shall be applied toward the resource's financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity

Auction, the financial assurance required prior to the auction pursuant to FAP will be released pursuant to the terms of the ISO New England Financial Assurance Policy.

III.13.1.9.2. Financial Assurance for New Generating Capacity Resources and New Demand Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Resource's offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Resource: (i) fails to provide the required financial assurance as described in the ISO New England Financial Assurance Policy or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4(c), it shall lose its Capacity Supply Obligation and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. Release of Financial Assurance.

Once a New Generating Capacity Resource or New Demand Resource achieves Commercial Operation and is tested for its capacity rating, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. Forfeit of Financial Assurance.

Where any financial assurance is forfeited pursuant to the provisions of Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to Section III.13 shall be used to reduce charges incurred by load in the relevant Capacity Zone to replace that capacity.

III.13.1.9.2.4. Financial Assurance for New Import Capacity Resources.

A New Import Capacity Resource that is backed by a new External Resource or will be delivered over an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource or the Elective Transmission Upgrade achieves Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. Qualification Process Cost Reimbursement Deposit.

For each New Capacity Show of Interest Form and New Demand Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below (“Qualification Process Cost Reimbursement Deposit”). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project’s critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of

the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff or where a resource modification does not require a revision to the Interconnection Agreement.

New Generating Resources \geq 20 MW or an Import Capacity Resource associated with an Elective Transmission Upgrade that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff	New Generating Resources < 20 MW and \geq 2 MW	Imports and New Demand Resources (including Distributed Generation)		New Generating Resources < 2 MW
<i>Including Up-rates, Re-powering, Environmental</i>	<i>Including Up-rates, Re-powering, Environmental Compliance &</i>			

<i>Compliance & Intermittent Power Resources</i>	<i>Intermittent Power Resources</i>			
\$25,000	\$7,500	\$1,000		\$500
<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>	<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>			
\$15,000	\$6500	n/a		n/a

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for Commercial Operation, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s) associated with the qualification process and critical path schedule monitoring, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO’s consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
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For all resources except Demand Resources, Nov. 1, 2006 through Jan. 2, 2007 For Demand Resources, Dec. 18, 2006 through Feb. 28, 2007	Apr. 30, 2007	June 15, 2007	Feb. 4, 2008	June 1, 2010
Sept. 18, 2007 through Nov. 14, 2007	Mar. 14, 2008	Apr. 29, 2008	Dec. 8, 2008	June 1, 2011
July 15, 2008 through Sep. 16, 2008	Feb. 3, 2009	Feb. 17, 2009	Oct. 5, 2009	June 1, 2012
May 15, 2009 through July 14, 2009	Dec. 1, 2009	Dec. 15, 2009	Aug. 2, 2010	June 1, 2013
Mar. 15, 2010 through May 14, 2010	Oct. 1, 2010	Oct. 15, 2010	June 6, 2011	June 1, 2014
Mar. 1, 2011 through Mar. 14, 2011	Aug. 1, 2011	Aug. 15, 2011	Apr. 2, 2012	June 1, 2015
Jan. 3, 2012 through Jan. 17, 2012	June 1, 2012	June 15, 2012	Feb. 4, 2013	June 1, 2016
Feb. 14, 2013 through Feb. 28, 2013	June 3, 2013	June 17, 2013	Feb. 3, 2014	June 1, 2017

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

- (a) each Capacity Commitment Period shall begin in June;
- (b) the New Capacity Show of Interest Submission Window will be in February (after the Forward Capacity Auction for the prior Capacity Commitment Period), approximately four years and three months before the beginning of the Capacity Commitment Period;
- (c) the Existing Capacity Qualification Deadline will be in June just over four years before the beginning of the Capacity Commitment Period;
- (d) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and
- (e) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

The table below shows this generic timeline for the Capacity Commitment Period beginning in year “X”, where X is any year after 2015.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
Feb. (X-4)	June (X-4)	June/July (X-4)	Feb. (X-3)	June X

III.13.1.11 Opt-Out for Resources Electing Multiple-Year Treatment.

Beginning in the qualification process for the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), any resource that had elected in a Forward Capacity

Auction prior to the ninth Forward Capacity Auction (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer cleared may, by submitting a written notification to the ISO no later than the Existing Capacity Qualification Deadline (or, in the case of the ninth Forward Capacity Auction, no later than September 19, 2014), opt-out of the remaining years of the resource's multiple-year election. A decision to so opt-out shall be irrevocable. A resource choosing to so opt-out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.

III.13.5. Bilateral Contracts in the Forward Capacity Market.

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals and Supplemental Availability Bilaterals in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.

A resource having a Capacity Supply Obligation seeking to shed that obligation (“Capacity Transferring Resource”) may enter into a bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part (“Capacity Supply Obligation Bilateral”), to a resource, or portion thereof, having Qualified Capacity for that Capacity Commitment Period that is not already obligated (“Capacity Acquiring Resource”), subject to the following limitations

- (a) A monthly Capacity Supply Obligation Bilateral must be coterminous with a calendar month, and an annual Capacity Supply Obligation Bilateral must be coterminous with a Capacity Commitment Period.
- (b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly Capacity Supply Obligation of the Capacity Transferring Resource during the period covered by the Capacity Supply Obligation Bilateral. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly amount of unobligated Qualified Capacity (that is, Qualified Capacity as determined in the most recent Forward Capacity Auction or reconfiguration auction qualification process that is not subject to a Capacity Supply Obligation for the relevant time period) of the Capacity Acquiring Resource during the period covered by the Capacity Supply Obligation Bilateral, as determined in the qualification process for the most recent Forward Capacity Auction or annual reconfiguration auction prior to the submission of the Capacity Supply Obligation Bilateral to the ISO.
- (c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource’s unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.

(d) A Real-Time Emergency Generation Resource may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource.

(e) [Reserved.]

(f) [Reserved.]

(g) Prior to April 1, 2015, if the Capacity Acquiring Resource is an Import Capacity Resource, then the Capacity Transferring Resource must also be an Import Capacity Resource on the same external interface.

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant Capacity Commitment Period month.

(j) A resource that has not achieved Commercial Operation by the submission deadline for a monthly Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that Capacity Commitment Period month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a Capacity Supply Obligation Bilateral in an amount up to the absolute value of its Capacity Supply Obligation.

III.13.5.1.1. Process for Approval of Capacity Supply Obligation Bilaterals.

III.13.5.1.1.1. Timing of Submission.

The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO before or during submittal windows, as defined in the ISO New England Manuals and ISO New England Operating

Procedures. The ISO will issue a schedule of the submittal windows for annual and monthly Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

III.13.5.1.1.2. Application.

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, in \$/kW-month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of \$0.00/kW-month.

III.13.5.1.1.3. ISO Review.

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral, and shall reject the Capacity Supply Obligation Bilateral if any of the provisions of this Section III.13.5.1 are not met. For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.

(b) After the close of the relevant submittal window, each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards will remain satisfied if the capacity associated with the Capacity Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO's reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved generation or Demand Response Resource outage information, and will include transmission security

studies. The ISO will review all confirmed monthly Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. For a monthly Capacity Supply Obligation Bilateral, the ISO shall obtain and consider information from the Local Control Center regarding whether the Capacity Supply Obligation of the Capacity Transferring Resource is needed for local system conditions and whether it is adequately replaced by the Acquiring Resource.

The ISO will review the net impact of all annual Capacity Supply Obligation Bilaterals to ensure that the regional and local adequacy and other reliability needs achieved through the Forward Capacity Auction are maintained in the Capacity Transferring Resource's Capacity Zone and the Capacity Acquiring Resource's Capacity Zone or across the external interface.

If after its review of the net impact of all annual Capacity Supply Obligation Bilaterals the ISO determines that the regional and local adequacy and other reliability needs achieved through the Forward Capacity Auction are not maintained, and for all monthly Capacity Supply Obligation Bilaterals, the the ISO will approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. If multiple Capacity Supply Obligation Bilaterals are submitted between the same resources, they may be reviewed together as one transaction and the most recent confirmation time among the related transactions will be used to determine the review order of the grouped transaction. Transactions that cannot meet the applicable reliability needs will only be accepted or rejected in their entirety and the resources will not be accepted or rejected in part for purposes of that transaction. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected for reliability reasons the Lead Market Participant or Project Sponsor, as appropriate, for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the reliability need prompting such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

III.13.5.1.1.4. Approval.

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply Obligation of the Capacity Acquiring Resource shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

III.13.5.2. Capacity Load Obligations Bilaterals.

A Market Participant having a Capacity Load Obligation seeking to shed that obligation (“Capacity Load Obligation Transferring Participant”) may enter into a bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone (“Capacity Load Obligation Bilateral”) to any Market Participant seeking to acquire a Capacity Load Obligation (“Capacity Load Obligation Acquiring Participant”). A Capacity Load Obligation Bilateral must be in whole calendar month increments, may not exceed one year in duration, and must begin and end within the same Capacity Commitment Period. A Capacity Load Obligation Transferring Participant will be permitted to transfer, and a Capacity Load Obligation Acquiring Participant will be permitted to acquire, a Capacity Load Obligation if after entering into a Capacity Load Obligation Bilateral and submitting related information to the ISO within the specified submittal time period, the ISO approves such Capacity Load Obligation Bilateral.

III.13.5.2.1. Process for Approval of Capacity Load Obligation Bilaterals.

III.13.5.2.1.1. Timing.

Either the Capacity Load Obligation Transferring Participant or the Capacity Load Obligation Acquiring Participant may submit a Capacity Load Obligation Bilateral to the ISO. All Capacity Load Obligation Bilaterals must be submitted to the ISO in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

III.13.5.2.1.2. Application.

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following : (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.13.5.2.1.3. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section II.13.5.2 are not met.

III.13.5.2.1.4. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral.

III.13.5.3. Supplemental Availability Bilaterals.

A resource's availability score during a Shortage Event may be supplemented by entering into a Supplemental Availability Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. Designation of Supplemental Capacity Resources.

III.13.5.3.1.1. Eligibility.

~~Demand Response Capacity Resources and~~ Generating Capacity Resources that are not Intermittent Power Resources or Settlement Only Resources may be designated as Supplemental Capacity Resources. A Generating Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource's CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales submitted in accordance with Section III.1.10.7(f) from that resource and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource. ~~A Demand Response Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource's Qualified Capacity from the Forward Capacity Auction for the current Capacity Commitment~~

~~Period pursuant to Section III.13.1.4.1 and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource.~~

III.13.5.3.1.2. Designation.

The designation of a Supplemental Capacity Resource must be made by the resource's Lead Market Participant. The designation shall indicate the term for which the resource is designated as a Supplemental Capacity Resource, which shall be in Operating Day increments, no less than one Operating Day, and no greater than one calendar month. Such designation shall indicate the MW amount being designated as a Supplemental Capacity Resource, and the Capacity Zone in which the resource is located. Such designation must be submitted to the ISO no later than the deadline for the submission of Supply Offers in the Day-Ahead Energy Market for the first Operating Day of the indicated term.

III.13.5.3.1.3. ISO Review.

The ISO shall review the information provided in submission of the designation as a Supplemental Capacity Resource, and shall reject the designation for any of the hours in which any of the provisions of this Section III.13.5.3.1 are not met.

III.13.5.3.1.4. Effect of Designation.

Regardless of whether it ever becomes subject to a Supplemental Availability Bilateral as described in Section III.13.5.3.2, the portion of a resource designated as a Supplemental Capacity Resource is subject to the same energy market offer requirements applicable to a resource having a Capacity Supply Obligation as described in Sections III.13.6.1.1.1 and III.13.6.1.1.2 for Generating Capacity Resources, ~~and as described in Sections III.13.6.1.5.1. and III.13.6.1.5.2. for Demand Response Capacity Resources for the entire term indicated in the designation described in Section III.13.5.3.1.2.~~

III.13.5.3.2. Submission of Supplemental Availability Bilaterals.

The Lead Market Participant for a resource previously designated as a Supplemental Capacity Resource in accordance with the provisions of Section III.13.5.3.1 for a term that included a Shortage Event may submit a Supplemental Availability Bilateral to the ISO assigning all or a portion of its available capability up to its designated supplemental capacity in each hour of that Shortage Event to a Generating Capacity Resource ~~or Demand Response Capacity Resource~~ having a Capacity Supply Obligation during that Shortage Event ("Supplemented Capacity Resource"). No other Market Participant may submit a Supplemental Availability Bilateral. The Supplemental Capacity Resource and the Supplemented Capacity Resource must either: (i) be located in the same Reserve Zone (although in no case may a

Supplemental Capacity Resource located in an export-constrained Capacity Zone provide supplemental availability outside of that export-constrained Capacity Zone); or (ii) be located in different Reserve Zones such that direction of flow between the Supplemental Capacity Resource and the Supplemented Capacity Resource is counter to any Reserve Zone or Capacity Zone constraint. For purposes of this Section III.13.5.3.2, a Reserve Zone having a locational reserve requirement (established pursuant to Section III.9.2.2) that is less than or equal to zero shall be considered to be unconstrained with respect to the neighboring Reserve Zone. A Supplemental Capacity Resource may submit Supplemental Availability Bilaterals with multiple Supplemented Capacity Resources, but each MW of supplemental capacity may only be assigned to one Supplemented Capacity Resource. No Supplemental Capacity Resource may itself be a Supplemented Capacity Resource for an hour.

III.13.5.3.2.1. Timing.

A Supplemental Availability Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the month associated with the Supplemental Availability Bilateral, a Supplemental Availability Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Supplemental Availability Bilateral may be revised by the parties to the transaction throughout the resettlement process). A Supplemental Availability Bilateral must be confirmed by the Lead Market Participant for the Supplemented Capacity Resource no later than the same deadline that applies to submission of the Supplemental Availability Bilateral.

III.13.5.3.2.2. Application.

The submission of a Supplemental Availability Bilateral to the ISO shall include the following: (i) the resource identification number for the Supplemental Capacity Resource; (ii) the resource identification number for the Supplemented Capacity Resource; (iii) the MW amount of capacity being assigned from the Supplemental Capacity Resource to the Supplemented Capacity Resource; (iv) the term of the transaction, which shall be in hourly increments coinciding with hourly boundaries, no less than one hour, and no greater than one calendar month.

III.13.5.3.2.3. ISO Review.

The ISO shall review the information provided in submission of the Supplemental Availability Bilateral, and shall reject the Supplemental Availability Bilateral if any of the provisions of this Section III.13.5.3 are not met. The ISO shall reject the applicability of a Supplemental Availability Bilateral in any hour of

a Shortage Event unless: (i) the Supplemental Capacity Resource was on-line and following ISO dispatch instructions during that hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is ~~(a)~~ less than or equal to the difference between the Generating Capacity Resource's Economic Maximum Limit as submitted or redeclared by the Lead Market Participant and the Supplemental Capacity Resource's Capacity Supply Obligation ~~or (b) less than or equal to the difference between (the greater of the sum of the Real Time Demand Reduction Obligations of the Demand Response Resources associated with the Demand Response Capacity Resource or the lesser of ((the sum of the Demand Response Baselines of the Demand Response Assets comprising the Demand Response Resources associated with the Demand Response Capacity Resource as adjusted pursuant to Section III.8B.5, plus the Net Supply Limit of the Demand Response Resources), the Hourly Adjusted Audited Demand Reduction, or (the Maximum Reduction as submitted or redeclared by the Lead Market Participant plus the Net Supply Limit of the Demand Response Resources))), adjusted for average avoided peak transmission and distribution losses as addressed in Section III.13.7.1.5.10, and the Supplemental Capacity Resource's Capacity Supply Obligation;~~ or (ii) the Supplemental Capacity Resource was offline for the hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is less than or equal to the difference between the sum of the Supplemental Capacity Resource's Real-Time Reserve Designations of TMNSR, TMSR and TMOR and the Supplemental Capacity Resource's Capacity Supply Obligation.

III.13.5.3.2.4. Effect of Supplemental Availability Bilateral.

A Supplemental Availability Bilateral does not affect in any way either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Supplemental Availability Bilateral is to modify the Supplemental Capacity Resource's availability score as described in Section III.13.7.1.1.4.

III.13.6. Rights and Obligations.

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. Generating Capacity Resources.

III.13.6.1.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

- (a) the sum of the Generating Capacity Resource's Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours; or
- (b) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a) due to physical design limits, then the resource shall be offered into the Day-Ahead Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero

or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.

III.13.6.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice.

Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the known capability of the resource. A resource failing to comply with this requirement shall be subject to economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.1.3. [Reserved.]

III.13.6.1.1.4. [Reserved.]

III.13.6.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1 and the requirement to provide to the ISO, upon request and as soon as practicable, confirmation of gas volume schedules sufficient to deliver the energy scheduled for each Generating Capacity Resource using natural gas;
- (c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.1.2. Import Capacity Resources.

III.13.6.1.2.1. Energy Market Offer Requirements.

A Market Participant must offer energy associated with an Import Capacity Resource with a Capacity Supply Obligation into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions for every hour of each Operating Day at the same external interface totaling an amount (MW) equal to the Capacity Supply Obligation unless the Import Capacity Resource is associated with an External Resource that is on an outage. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with this requirement may be subject to sanctions pursuant to Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.2 for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.

The offer requirements of Section III.13.6.1.2.1 will not apply to External Transactions associated with the VJO and NYPA Import Capacity Resources specified in Section III.13.1.3.3(c) for the duration of the contract provided the transactions are self-scheduled in both the Day-Ahead Energy Market and Real-Time Energy Market. If the energy associated with these contracts is not self-scheduled, the offer requirements and provisions of this section will apply to the applicable contract.

(a) All priced External Transactions associated with an Import Capacity Resource with a Capacity Supply Obligation must be offered each hour at or below the greater of either: (1) the offer threshold specified in Section III.13.6.1.2.1(b) for the Operating Day; (2) the offer threshold determined for the prior Operating Day; and (3) for any priced External Transactions from the New York Control Area the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface.

(b) A daily offer threshold will be determined for each Operating Day and will apply to each hour of the Operating Day. From June 1, 2010 to May 31, 2013 the daily offer threshold is equal to the product of the PER Proxy Unit heat rate as described in Section III.13.7.2.7.1.1(b)(iii) and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation of day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis. After May 31, 2013 the daily offer threshold is equal to the product of the applicable Forward Reserve Heat Rate as described in Section III.9.6.2 and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven

percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.

(c) Submittal of External Transactions to the Day-Ahead Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource requires submittal of matching energy transactions to the Real-Time Energy Market; the External Transactions submitted to the Real-Time Energy Market must match the External Transactions submitted to the Day-Ahead Energy Market, subject to the right to submit different prices into the Real-Time Energy Market.

(d) External Transactions submitted to the Real-Time Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource must be submitted prior to the offer submission deadline for the Day-Ahead Energy Market the day before the Operating Day for which they are intended to be scheduled.

(e) A Market Participant submitting a priced External Transaction supporting an Import Capacity Resource with a Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must link the transaction to the associated transmission reservation and NERC E-Tag no later than one hour before the operating hour in order to be eligible for scheduling in the Real-Time Energy Market. If a Market Participant does not link the transaction to the associated transmission reservation and NERC E-Tag in the Real-Time Energy Market for any hour during which the External Transaction would otherwise have been economically and reliably scheduled in the Real-Time Energy Market, the associated Import Capacity Resource shall be treated as having not delivered energy for the hour despite ISO requested dispatch under Section III.13.7.1.2 and III.13.7.2.7.2. A Market Participant submitting any other External Transaction to the Real-Time Energy Market must comply with the requirements in Section III.1.10.7(e) with respect to linking the transaction to the associated transmission reservation and NERC E-Tag.

III.13.6.1.2.2. Additional Requirements for Import Capacity Resources.

Import Capacity Resources are subject to the following additional requirements:

(a) information submittal requirements for External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals;

(b) resource backed Import Capacity Resources shall be subject to the outage requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures. Control Area backed Import Capacity Resources are not subject to such outage requirements;

(c) resource backed Import Capacity Resources are subject to the voluntary and mandatory re-scheduling of maintenance procedures outlined in the ISO New England Operating Procedures and ISO New England Manuals.

(d) at the time of submittal, each External Transaction shall reference the associated Import Capacity Resource.

III.13.6.1.3. Intermittent Power Resources.

III.13.6.1.3.1. Energy Market Offer Requirements.

Intermittent Power Resources may submit offers into the Day-Ahead Energy Market. Such resources are required to submit offers for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

III.13.6.1.3.2. [Reserved.]

III.13.6.1.3.3. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals;
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals;
- (c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.1.4.1. Energy Market Offer Requirements.

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.4.2. Additional Requirements for Settlement Only Resources.

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources having a Capacity Supply Obligation are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals;
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals;
- (c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.5. Demand Resources.

III.13.6.1.5.1. Energy Market Offer Requirements.

Seasonal Peak Demand Resources, On-Peak Demand Resources and Real-Time Emergency Generation Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Markets. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E.

Commencing June 1, 2018⁷, a Market Participant with a Demand Response Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers for its Demand Response Resources into the Day-Ahead Energy Market and Real-Time Energy Market. The sum of the Demand Reduction Offers must be equal to or greater than the Demand Response Capacity Resource's Capacity Supply Obligation whenever the Demand Response Resources are physically available. If the Demand Response Resources are physically available at a level less than the Demand Response Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers will equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand

Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet one of the following requirements:

- (a) the sum of the Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time plus Minimum Reduction Time plus Minimum Time Between Reductions is less than or equal to 72 hours.
- (b) the sum of the Demand Response Resource's Minimum Reduction Time plus the Minimum Time Between Reductions is less than or equal to 24 hours.

III.13.6.1.5.2. Requirement that Offers Reflect Accurate Demand Response Capacity Resource Operating Characteristics.

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a resource Demand Response Resources associated with a Demand Response Capacity Resource must reflect the then-known operating characteristics of the resource. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this requirement shall be subject to economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.5.3. Additional Requirements for Demand Resources.

Demand Resources shall comply with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals and the auditing and rating requirements as detailed in Section III.13.6.1.5.4 and the ISO New England Manuals. Demand Response Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

- (a) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1;
- (b) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.1.5.4. Demand Response Auditing.

Demand Resources shall be subject to ISO conducted audits for the purposes of:

- (a) Auditing Demand Reduction Values or determining the Audited Demand Reduction for a Demand Resource;
- (b) Verifying the Commercial Operation of a Demand Resource; and
- (c) Verifying the Demand Reduction Value or the Audited Demand Reduction of the Demand Resource when the ISO, based on objective criteria, has determined that the Demand Reduction Value or the Audited Demand Reduction of a Demand Resource may not be credible.

New Demand Response Asset Audits shall be performed pursuant to Section III.13.6.1.5.4.8.

III.13.6.1.5.4.1. General Auditing Requirements for Demand Resources Excluding Demand Response Capacity Resources.

- (a) Audits of a Demand Resource will be conducted by simultaneously evaluating the performance of each demand asset that is mapped to that Demand Resource.
- (b) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Real-Time Demand Response Resources containing Real-Time Demand Response Assets that are located behind the same end-use customer meter as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource.
- (c) An audit is valid beginning with the month in which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like seasonal DR Auditing Period. Additional audits performed in a month shall not replace the results of the initial audit conducted in a month and are valid on the first of the subsequent month following the audit. Audit results shall not replace a Demand Reduction Value that is based on Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours.

(d) If one or more demand assets of a Demand Resource do not have audit results at the time the Demand Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those demand assets toward the audit value of the Demand Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit provided the demand asset was available for dispatch by the ISO in that prior month, and if the demand asset was not available for dispatch in that prior month, then the 1st of the month in which the demand asset was available for dispatch.

III.13.6.1.5.4.2. General Auditing Requirements for Demand Response Capacity Resources.

- (a) Audits of Demand Response Resources associated with a Demand Response Capacity Resource will be conducted by simultaneously evaluating the performance of each Demand Response Asset that is mapped to a Demand Response Resource. The Demand Response Resources associated with a Demand Response Capacity Resource are not required to be evaluated simultaneously.
- (b) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Demand Response Resources containing Demand Response Assets that are located behind the same Retail Delivery Point as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource. When the output of the Real-Time Emergency Generation Asset is greater than the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of the Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Net Supply is reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset.
- (c) An audit is valid beginning with the date on which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like Seasonal DR Audit period. For the Capacity Commitment Period commencing on June 1, 2018~~7~~, the audit results for Demand Response Resources comprised of Demand Response Assets that were associated with a Real-Time Demand Response Resource in the prior Capacity Commitment Period shall be the sum of the audit results for those assets in the prior like Seasonal DR Audit period. When using audit results from a period prior to June 1, 2018~~7~~ for those former Real-Time Demand Response Assets, the Audited Full Reduction Time shall be 30 minutes.

- (d) If one or more Demand Response Assets of a Demand Response Resource do not have an Audited Demand Reduction at the time the Demand Response Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those Demand Response Assets toward the Audited Demand Reduction of the Demand Response Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit, provided the Demand Response Asset was available for dispatch by the ISO in that prior month, and if the Demand Response Asset was not available for dispatch in that prior month, then the 1st of the month in which the Demand Response Asset was available for dispatch.

III.13.6.1.5.4.3. Seasonal DR Audits.

A Seasonal DR Audit must be conducted for each Demand Resource during each seasonal DR Auditing Period.

III.13.6.1.5.4.3.1. Seasonal DR Audit Requirement.

A Market Participant shall submit each Demand Resource to an ISO initiated audit each season to verify the Demand Reduction Value or Audited Demand Reduction for the resource for one or more months of the season. The Seasonal DR Audit must be requested by the Market Participant for the Demand Resource within each Capacity Commitment Period in which the Demand Resource has a Capacity Supply Obligation. The summer DR Auditing Period begins on June 1 and ends on August 31. The winter DR Auditing Period begins on December 1 and ends on January 31. For all Demand Resources other than Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the audit results for the months of June, July, and August, and audits performed during the winter DR Auditing Period will be used to establish the audit results for the months of December and January. For Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource summer months of June, July, August, September, October, November, and the following April and May, and audits performed during the winter DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource winter months of December and the following January, February and March.

III.13.6.1.5.4.3.2. Failure to Request or Perform an Audit.

If by the 1st of August for the summer DR Auditing Period or by the 1st of January for the winter DR Auditing Period a Market Participant has not requested a Seasonal DR Audit for a Demand Resource, the Market Participant shall be deemed to have requested a Seasonal DR Audit on those respective dates. A Demand Resource that does not successfully perform a Seasonal DR Audit for a DR Auditing Period shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

III.13.6.1.5.4.3.3. Use of Event Performance Data to Satisfy Audit Requirements for Certain Resources.

A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource that has received a Dispatch Instruction in a season for 100% of its highest CSO for the current DR Auditing Period lasting at least one hour, not including the 30 minute Demand Response Resource Notification Time, may use the first 60 minute period of the event after the 30 minute Demand Response Resource Notification Time to satisfy the Seasonal DR Audit requirement for the applicable DR Auditing Period, subject to the provisions of Section III.13.6.1.5.4.1(b). A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource's audit value under this provision is based on the average load reduction or output demonstrated over the duration of the qualifying 60 minute period.

A Market Participant must request that an event be used to satisfy the Demand Resource's Seasonal DR Audit requirement or replace a currently effective audit result within seven days of the Operating Day on which the Dispatch Instruction for the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is received.

III.13.6.1.5.4.3.3.1. Demand Response Capacity Resources.

A Demand Response Capacity Resource may elect to use performance associated with a [Capacity Scarcity Condition](#), ~~Shortage Event as defined in Section III.13.7.1.1.1~~ or a time period when the ISO has declared a capacity deficiency pursuant to ISO New England Operating Procedure No. 4, that occurs during a DR Auditing Period in place of requesting a Seasonal DR Audit; provided that any Demand Response Asset of a Demand Response Resource associated with the Demand Response Capacity Resource on a forced curtailment or scheduled curtailment as defined in Section III.~~8B.613.7.1.5.10.2~~ is assessed a zero audit value.

If a Demand Response Resource associated with a Demand Response Capacity Resource does not reduce demand for some portion of the event, the audit results of its Demand Response Assets shall be set to zero. Otherwise, the Demand Response Resources associated with a Demand Response Capacity

Resource will be measured based upon their offered parameters per Section III.13.6.1.5.4.6(d), and the Audited Demand Reduction for each Demand Response Resource will be capped at the average Desired Dispatch Point for the Demand Response Resource over the audit duration by proportionally reducing each associated Demand Response Asset's audit results.

Within 7 calendar days of the event, the participant must inform the ISO that it wishes to use dispatch performance during the event to establish the Demand Response Resource's Audited Demand Reduction.

If ~~a an event~~~~Shortage Event~~ occurs before a Demand Response Resource has established an Audited Demand Reduction value and the resource was not dispatched during the ~~Shortage E~~vent at a level equal to its Maximum Reduction, a Market Participant may elect within seven calendar days after the event to set the Audited Demand Reduction of the Demand Response Resource equal to its CLAIM10 or CLAIM30 value at the time of the event as determined pursuant to Section III.9.5.3.

A Market Participant may elect to use performance associated with a CLAIM10 or CLAIM30 audit of a Demand Response Resource that occurs during a DR Auditing Period in place of requesting a Seasonal DR Audit of that resource provided that the audit was conducted in a manner that meets the requirements of a Seasonal DR Audit. Within seven calendar days of the CLAIM10 or CLAIM30 audit, the Market Participant must inform the ISO that it wishes to use dispatch performance during the audit to establish the Demand Response Resource's Seasonal DR Audit value.

III.13.6.1.5.4.4. Demand Resource Commercial Operation Audit.

(a) A Market Participant with a Demand Resource that has one or more increments that have not demonstrated commercial operation prior to the commencement of a Capacity Commitment Period shall perform a Demand Resource Commercial Operation Audit. The results of the Demand Resource Commercial Operation Audit shall be used to verify the commercial capacity of the Demand Resource and establish the Audited Demand Reduction of a Demand Response Resource.

(b) If a Demand Resource Commercial Operation Audit is not performed prior to the commencement of the Capacity Commitment Period, an audit must be requested in time for performance within the first month in which the Demand Resource has a Capacity Supply Obligation in the Capacity Commitment Period or the Commercial Operation Date, whichever is earlier. A Demand Resource that does not

successfully perform a Demand Resource Commercial Operation Audit prior to the end of the first month in which the Demand Resource has a Capacity Supply Obligation shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

(c) A Demand Resource that fails to demonstrate through its Demand Resource Commercial Operation Audit a demand reduction in the amount of its Capacity Supply Obligation shall be subject to the provisions of Section III.13.1.9 and Section III.13.3.4.

(d) A Market Participant may request additional Demand Resource Commercial Operation Audits during a Capacity Commitment Period to verify an increase in the commercial capacity of a Demand Resource.

(e) If a Demand Resource has summer Qualified Capacity, a Demand Resource Commercial Operation Audit must be performed during the summer season (April through November) to verify the commercial capacity of the resource. A Demand Resource Commercial Operation Audit performed during the winter season (December through March) may only be used to verify the winter commercial capacity of the resource.

(f) A Demand Resource Commercial Operation Audit performed during a summer DR Auditing Period or winter DR Auditing Period may be used to satisfy the Seasonal DR Audit requirement for the same seasonal period. If a Demand Resource conducts a Demand Resource Commercial Operation Audit outside of a summer DR Auditing Period or winter DR Auditing Period, the Seasonal DR Audit requirement shall not be satisfied, however the results shall be used in the calculation of the summer Seasonal DR Audit value or winter Seasonal DR Audit value as follows:

- (1) A Demand Resource Commercial Operation Audit conducted in the months of September, October, November, April, or May shall be considered a summer Seasonal DR Audit;
- (2) A Demand Resource Commercial Operation Audit conducted in February or March shall be considered a winter Seasonal DR Audit.

III.13.6.1.5.4.5. Additional Audits.

The ISO may initiate an audit to verify the Demand Reduction Value or Audited Demand Reduction of a Demand Resource when an evaluation based on objective criteria indicates a Market Participant is

claiming demand reductions in excess of the Demand Resource's actual capability. Such criteria include, but are not limited to:

- (a) A pattern of submitting to the ISO a level of available interruption that is less than the resource's Demand Reduction Value or Audited Demand Reduction during the same time period;
- (b) Actual loads for the underlying assets of the resource that, when aggregated, are below the resource's Demand Reduction Value or Audited Demand Reduction; or
- (c) Failure to achieve the dispatched interruption.

The results of an additional audit shall replace the results of the last like Seasonal DR Audit or Demand Resource Commercial Operation Audit.

The ISO may perform additional audits for a Demand Resource to establish the audit results or Audited Demand Reduction and the performance of the installed measures of the demand asset or Demand Response Asset. This additional auditing may consist of two levels.

- (a) Level 1 Audit: the ISO will establish the audit results by conducting a review of records of the demand asset or Demand Response Asset to verify that the reported measures have been installed and are operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.
- (b) Level 2 Audit: the ISO shall establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of measures in the demand asset or Demand Response Asset. Such an audit may include a random or select sample of facilities and measures.

A level 1 audit is not required to precede a level 2 audit. If the results of the audit indicate that the demand reduction capability of the Demand Resource is less than or greater than its Demand Reduction Value or Audited Demand Reduction in the same period, then the Demand Reduction Value or Audited Demand Reduction shall be adjusted to the value demonstrated through the audit.

III.13.6.1.5.4.6. Audit Methodologies.

- (a) For On-Peak Demand Resources, audit results shall be established based on the Average Hourly Output or Average Hourly Load Reduction in the DR Auditing Period.
- (b) For Seasonal Peak Demand Resources, audit results shall be established based on Average Hourly Output or Average Hourly Load Reduction or their equivalent in the DR Auditing Period.
- (c) For Real-Time Demand Response Resources and Real-Time Emergency Generation Resources, audits will be conducted via a Dispatch Instruction sent by the ISO. Audit results for a Real-Time Demand Response Resource and Real-Time Emergency Generation Resource will be based on the sum of the average load reductions or average incremental output demonstrated during the audit by each demand asset mapped to the Demand Resource.
- (d) For Demand Response Resources associated with Demand Response Capacity Resources, audits will be conducted via a Dispatch Instruction. Audit results for the Demand Response Resources will be based on the sum of the average demand reductions demonstrated during the audit by each Demand Response Asset associated with the Demand Response Resource that is mapped to the Demand Response Capacity Resource using (i) each Demand Response Resource's Offered Full Reduction Time to establish the start of the audit period and (ii) the Minimum Reduction Time adjusted for ramping time as the audit duration. The Offered Full Reduction Time is the Demand Response Resource Notification Time plus the Demand Response Resource Start-Up Time plus ((the Maximum Reduction minus the Minimum Reduction) divided by the Demand Response Resource Ramp Rate). For purposes of determining the Offered Full Reduction Time, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Maximum Reduction is reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset.

III.13.6.1.5.4.7. Requesting and Performing an Audit.

- (a) Seasonal DR Audits and Demand Resource Commercial Operation Audits will be performed following the request of the Market Participant. Audits will be performed within 20 Business Days of the date requested by the Market Participant. The date and time of the audit will be unannounced. An audit

request may be denied by the ISO, and an audit may be rescheduled, if its performance will jeopardize the reliable operation of the electrical system.

(b) Seasonal DR Audits may be performed on different dates and at different times for Demand Response Resources associated with a Demand Response Capacity Resource if the Demand Response Resources have different offer parameters. In addition, the ISO will only schedule Demand Resource Commercial Operation Audits of a Demand Response Resource with Demand Response Assets that do not have an Audited Demand Reduction value.

(c) New Demand Response Asset Audits will be performed following the request of the Market Participant. The request for a New Demand Response Asset Audit by the Market Participant shall be made during the last seven days of the month. The audit will be performed on Business Days during the month following the date of the request by the Market Participant. The date and time of the audit will be unannounced. An audit request may be denied by the ISO, and an audit may be rescheduled, if its performance will jeopardize the reliable operation of the electrical system.

III.13.6.1.5.4.8. New Demand Response Asset Audits

A Market Participant may request a New Demand Response Asset Audit for all New Demand Response Assets that are mapped to a Demand Resource. The results of a New Demand Response Asset Audit may be used:

(a) In calculating the Seasonal DR Audit value for the Demand Resource to which the asset is mapped until the next Seasonal DR Audit for the full Demand Resource is conducted;

(b) In calculating the commercial capacity value of the Demand Resource for purposes of determining release of financial assurance pursuant to Section III.13.1.9.2.2, until the next Demand Resource Commercial Operation Audit is conducted;

(c) For determination regarding termination under Section III.13.3.4(c); and

(d) In the monthly calculation of a Demand Resource's Demand Reduction Value pursuant to Section III.13.7.1.5.7 and Section III.13.7.1.5.8.

When a New Demand Response Asset Audit is performed, the commercial capacity value and Seasonal DR Audit value of the Demand Resource to which the asset is mapped shall be updated to reflect any changes in the composition of the Demand Resource.

III.13.6.1.5.4.8.1. General Auditing Requirements for New Demand Response Assets.

(a) A New Demand Response Asset Audit will be conducted by simultaneously evaluating the performance of each New Demand Response Asset that is mapped to that Demand Resource.

(b) A New Demand Response Asset Audit is valid beginning with the month in which the audit is performed, and remains valid until the next Seasonal DR Audit is performed for a like season or until a Demand Resource Commercial Operation Audit is performed. Additional audits performed in a month shall not replace the results of the initial audit conducted in a month and are valid on the first of the month following the audit. Audit results shall not be used in the calculation of a Demand Reduction Value that is based on Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours.

III.13.6.1.5.5. Reporting of Forecast Hourly Demand Reduction.

A Market Participant with Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO a two-day forecast of each Demand Resource's Forecast Hourly Demand Reduction for each Operating Day. The Market Participant shall update its forecast, in accordance with the ISO New England Manuals and Operating Procedures, to reflect its estimate of each Demand Resource's Forecast Hourly Demand Reduction.

III.13.6.1.5.6. Reporting of Monthly Maximum Forecast Hourly Demand Reduction.

A Market Participant with Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO each month a forecast of each resource's monthly maximum Forecast Hourly Demand Reduction for each of the next 12 months.

III.13.6.2. Resources without a Capacity Supply Obligation.

A resource that does not have any Capacity Supply Obligation shall comply with the requirements in this Section III.13.6.2, and shall not be subject to the requirements set forth in Section III.13.6.1 during the

Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.13.6.2.1. Generating Capacity Resources.

III.13.6.2.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.1.1.1. Day-Ahead Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offered energy clears in the Day-Ahead Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the operating day, including the obligation to follow ISO dispatch instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.1.2. Real-Time Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, must Self-Schedule in order to participate in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.

Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

- (a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;
- (b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Generating Capacity Resources having no Capacity Supply Obligation are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.2.2. [Reserved.]

III.13.6.2.3. Intermittent Power Resources.

III.13.6.2.3.1. Energy Market Offer Requirements.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.3.2. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals; and
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals.

III.13.6.2.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.2.4.1. Energy Market Offer Requirements.

A Settlement Only Resource may not submit an offer into the Day-Ahead Energy Market or the Real-Time Energy Market.

III.13.6.2.4.2. Additional Requirements for Settlement Only Resources.

Settlement Only Resources are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals;
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.2.5. Demand Resources.

III.13.6.2.5.1. Energy Market Offer Requirements.

Real-Time Emergency Generation Resources, Seasonal Peak and On-Peak Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E1. A Market Participant with a Demand Response Resource associated with a Demand Response Capacity Resource without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

For Demand Reduction Offers made into the Day-Ahead Energy Market and Real-Time Energy Market for such Demand Response Resources, the sum of the Demand Response Resource's Minimum Reduction Time plus the Minimum Time Between Reductions must also be less than or equal to 24 hours.

III.13.6.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with a Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response Capacity Resource without a Capacity Supply Obligation, may submit a Demand Reduction Offer into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer, up to the Maximum Reduction offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with a Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response Capacity Resource without a Capacity Supply Obligation, that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit a Demand

Reduction Offer in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.2. Additional Requirements for Demand Response Capacity Resources Having No Capacity Supply Obligation.

Demand Response Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

- (a) complying with the auditing and rating requirements as detailed in Section III.13.6.1.5.4 and the ISO New England Manuals;
- (b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and
- (c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Demand Response Capacity Resources having no Capacity Supply Obligation are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.3. Exporting Resources.

A resource that is exporting capacity not subject to a Capacity Supply Obligation to an external Control Area shall comply with this Section III.13.6.3 and the ISO New England Manuals. Intermittent Power Resources, Settlement Only Resources, and Demand Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7.

III.13.6.4. ISO Requests for Energy.

The ISO may request that a Demand Response Capacity Resource or Generating Capacity Resource having capacity that is not subject to a Capacity Supply Obligation provide energy for reliability purposes in the Real-Time Energy Market, but such resource shall not be obligated under Section III.13 of this Tariff by such a request to provide energy from that capacity, and shall not be subject to any availability penalties under Section III.13 of this Tariff by such a request for failure to provide energy from that

capacity that is not subject to a Capacity Supply Obligation. If such resource does provide energy from that capacity, the resource shall be paid based on its most recent offer and is eligible for NCPC.

III.13.6.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.13.6.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

III.13.7. Performance, Payments and Charges in the FCM.

During each month within each Capacity Commitment Period (“Obligation Month”), each resource that acquired or shed a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will be subject to payments, charges, penalties and adjustments for such activity. In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month shall have their performance measured throughout the month, based on the resource’s availability during any Shortage Events in the Obligation Month.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Performance Measures.

III.13.7.1.1. Generating Capacity Resources.

During each Capacity Commitment Period, each Generating Capacity Resource having a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will have its performance measured during each Obligation Month based on the resource’s availability during any Shortage Events during the month.

III.13.7.1.1.1. Definition of Shortage Events.

(a) In all Capacity Zones, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for Ten-Minute Non-Spinning Reserves shall be a Shortage Event.

(b) Prior to June 1, 2018⁷, in any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for the “minimum TMOR” requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement (described in Section III.2.7A(c)) when Action 2 under Operating Procedure No. 4 has also been implemented for the entire Capacity Zone shall also be a Shortage Event. ~~Beginning on June 1, 2017, in any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for the “minimum TMOR”~~

~~requirement sub-category of the system-wide Thirty Minute Operating Reserves requirement (described in Section III.2.7A(e)) shall also be a Shortage Event.~~

(c) Prior to June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be Action 2 under Operating Procedure No. 4, or any Operating Procedure No. 7 event, that is declared for the entire import-constrained Capacity Zone for thirty or more contiguous minutes and that is not also declared for the entire Rest-of-Pool Capacity Zone.

~~Beginning on June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for the local Thirty Minute Operating Reserves requirement (described in Section III.2.7A(e)) that is declared for the entire import-constrained Capacity Zone.~~

(d) In all cases, to be considered discrete Shortage Events, such events must be separated by at least 2.5 hours. Events that would satisfy the definition of Shortage Events except that they are separated by less than 2.5 hours shall be considered a single Shortage Event with a duration equal to the sum of the lengths of the underlying events. There shall be no more than two Shortage Events per Capacity Zone per day. If there are more than two Shortage Events in a day, only the first two Shortage Events that occur will be recognized.

(e) For the purposes of Section III.13.7.1.1.1(d), Shortage Events that cross daily boundaries will be considered to occur on the day in which the Shortage Event was triggered. Availability during Shortage Events that cross monthly boundaries will be applied to the Obligation Month in which the Shortage Event was triggered.

III.13.7.1.1.1.A Shortage Event Availability Score.

For each Shortage Event, the ISO shall calculate a Shortage Event Availability Score for each resource, as follows: For each hour containing any portion of the Shortage Event, the ISO shall multiply the resource's hourly availability score by the number of minutes of the Shortage Event in that hour, and then divide the product by the total number of minutes in the Shortage Event. The resulting values for each hour shall then be added together to determine the resource's Shortage Event Availability Score.

III.13.7.1.1.2. Hourly Availability Scores.

The ISO shall calculate an availability score for each resource for each hour that contains any portion of a Shortage Event. A resource's availability score for an hour, expressed as a percentage which may not

exceed 100 percent, shall be the sum of the resource's available MW in that hour plus any adjustments pursuant to Section III.13.7.1.1.4 divided by the resource's Capacity Supply Obligation. In the event that there are no Shortage Event hours during a month, no availability penalties will be assessed.

III.13.7.1.1.3. Hourly Available MW.

A resource's available MW in each hour that contains any portion of a Shortage Event shall be determined pursuant to the provisions of this Section III.13.7.1.1.3, provided, however, that in no case shall a resource's available MW in an hour exceed that resource's CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales from that resource).

(a) For a resource that is on-line with a metered output greater than zero and following ISO dispatch instructions, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(b) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification time plus cold start time of thirty minutes or less, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(c) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification plus cold start-up time of less than or equal to 12 hours (16 hours, during the first five Capacity Commitment Periods for resources with notification plus start-up times greater than 12 hours as of June 16, 2006) and the output, up to the Capacity Supply Obligation, was competitively offered into the Energy Market (i.e., capacity from the listed portion of the resource was offered at or below the appropriate Reference Level plus applicable conduct thresholds) but was not committed by the ISO and was consequently unavailable within 30 minutes, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(d) For a resource that is off-line but not meeting the requirements of either Section III.13.7.1.1.3(b) or Section III.13.7.1.1.3(c), the available MW in an hour shall be zero.

(e) For a resource that is on-line but not able to follow ISO dispatch instructions, the available MW in an hour shall be the resource's metered output for the hour.

(f) Where a resource is not committed due to an outage or derate of transmission equipment within the New England Control Area, other than an outage or de-rate of transmission equipment that is controlled by the owner of the resource or that constitutes a radial lead to a resource in the New England Control Area (other than radial leads to Wyman 4 and Stony Brook), that resource's available MW in an hour shall not be reduced as result. Maine Independence Station shall be considered available when derated or not committed because of a transmission constraint.

(g) Where a resource is denied a self-schedule request by the ISO and therefore was not available in the Real-Time Energy Market, that resource's available MW in an hour shall not be reduced as a result.

(h) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation and cannot conduct its capability audit by the first day of the Obligation Month, that resource's available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(i) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, that resource's available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(j) Where a resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), that resource will have its hourly available MW reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

III.13.7.1.1.4. Availability Adjustments.

(a) A resource's hourly availability score may be increased using a Supplemental Availability Bilateral as described in Section III.13.5.3. Where all of the requirements of Section III.13.5.3 are met, the amount of available MW from the Supplemented Capacity Resource during each hour of the Shortage Event will be increased by the amount of supplemental capacity specified in the Supplemental Availability Bilateral, provided, however, that only available capacity above the Supplemental Capacity

Resource's Capacity Supply Obligation, if any, during each hour of the Shortage Event may be counted as supplemental capacity for the Supplemented Capacity Resource. The sum of these amounts will be counted in determining the availability score of the Supplemented Availability Resource for the Shortage Event.

(b) A resource's hourly availability score may be increased when an asset associated with the resource is on a planned outage that was approved in the ISO's annual maintenance scheduling process. Market Participants may indicate when submitting a planned outage request that the outage is to be considered exempt as described in ISO New England Operating Procedure No. 5. In such cases the associated resource's hourly available MWs may be increased by an amount up to the outage MWs requested, provided that the resource has not exceeded the maintenance allotment hour limit regarding exempt approved planned outages at the time of the Shortage Event as described in the ISO New England Manuals. In the case of a Settlement Only Resource, a planned outage scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource's hourly availability score as described in this subsection.

III.13.7.1.1.5. Poorly Performing Resources.

Prior to the Forward Capacity Auction qualification process, the ISO shall determine whether a resource meets the following two criteria: in the most recent four consecutive Capacity Commitment Periods or the most recent 4 years in which the resource assumed a Capacity Supply Obligation: (a) the resource received 3 annual availability scores of less than or equal to 40 percent; and (b) the resource has failed to be available in its entirety during ten or more Shortage Events during that same period. The annual availability score for each Capacity Commitment Period shall be equal to the average of all availability scores as calculated for each hour during each Shortage Event. If both of these criteria are met, the resource shall be considered a Poorly Performing Resource and shall not be eligible to participate in any subsequent Forward Capacity Auctions, and may not assume an obligation through the reconfiguration auctions, or Capacity Supply Obligation Bilaterals until it either achieves an availability score of 60 percent or higher in three consecutive Capacity Commitment Periods or 3 consecutive years, or demonstrates to the ISO that the reasons for the inadequate availability scores have been remedied. For the purposes of determining whether a resource is a Poorly Performing Resource, its availability score while it is de-listed shall not be considered. For the purposes of returning from poorly performing status, the ISO, at the request of the resource owner, may consider performance while de-listed, but in no case shall the ISO use non-consecutive years for evaluating a resource's performance.

III.13.7.1.2. Import Capacity.

The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as defined in Section III.13.7.1.1.1. An Import Capacity Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1, as appropriate). An Import Capacity Resource's available MW in each hour that contains any portion of a Shortage Event shall be determined as follows:

(a) Where the corresponding External Transactions are delivering energy in accordance with ISO dispatch instructions, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(b) Where the corresponding External Transactions have been offered in accordance with the provisions of Section III.13.6.1.2 and is not delivering energy during the hour because the ISO has not requested dispatch of the transaction, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(c) Where the corresponding External Transactions have not been offered in accordance with the provisions of Section III.13.6.1.2 or have been offered in accordance with the provisions of Section III.13.6.1.2 and are not delivering energy during the hour despite ISO requested dispatch of the transaction, the resource's available MW in the hour shall be zero.

(d) Where the Import Capacity Resource was offered in accordance with the provisions of Section III.13.6.1.2 but cannot make Real-Time deliveries of energy because the relevant external interface is already flowing at its Total Transfer Capability into New England in Real-Time, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

III.13.7.1.2.1. Availability Adjustments.

The hourly availability score of an Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource is on a planned outage in the same manner as described in Section III.13.7.1.1.4(b).

III.13.7.1.3. Intermittent Power Resources.

The performance measure for Intermittent Power Resources, including Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.4. Settlement Only Resources.

III.13.7.1.4.1. Non-Intermittent Settlement Only Resources.

A Non-Intermittent Settlement Only Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively. Its available MW in an hour of a Shortage Event shall be the resource's metered output for the hour.

III.13.7.1.4.2. Intermittent Settlement Only Resources.

The performance measure for Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.5. Demand Resources.

III.13.7.1.5.1. Capacity Values of Demand Resources.

The Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, multiplied by one plus the percent average avoided peak transmission and distribution losses used by the ISO in its calculations of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. Beginning with the Capacity Commitment Period starting June 1, 2012 the Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by one plus the percent average avoided peak transmission and distribution losses used to calculate the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. For the first Forward Capacity Auction, the value of the Installed Capacity Requirement

divided by the 50/50 summer system peak load forecast shall be 1.143, and one plus the percent average avoided peak transmission and distribution losses shall be 1.08.

III.13.7.1.5.1.1. Special Provisions for Demand Resources that Cleared in the First through Seventh Forward Capacity Auctions in which Project Sponsor Elected to have its Capacity Supply Obligation and Capacity Clearing Price Apply for Multiple Capacity Commitment Periods.

For a Demand Resource that cleared in the Forward Capacity auction for the Capacity Commitment Period beginning June 1, 2010 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2010, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.143 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2011, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.161 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for any of the Capacity Commitment Periods beginning June 1, 2012 through the Capacity Commitment Period beginning in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply in a future Capacity Commitment Period, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.08. This special provision shall cease to apply once the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.2. Capacity Values of Certain Distributed Generation.

For those Distributed Generation resource assets that are capable of generating energy in excess of the facility load and capable of delivering the excess generation to the power grid, if across Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, as appropriate, a Distributed Generation resource asset's monthly average hourly output is greater than the monthly average hourly load of the

end-use customer to which the resource is directly connected, the Capacity Value of the portion of output exceeding the customer's load for the month will be the Demand Reduction Value for that portion of the output. No average avoided peak transmission and distribution losses shall be applied to Net Supply associated with a Demand Response Asset, Demand Response Resource, or Demand Response Capacity Resource.

III.13.7.1.5.3. Demand Reduction Values.

A Demand Reduction Value is a quantity of reduced demand produced by a Demand Resource and is calculated pursuant to Section III.13.7.1.5.4, III.13.7.1.5.5, III.13.7.1.5.6, III.13.7.1.5.7 and III.13.7.1.5.8.

III.13.7.1.5.4. Calculation of Demand Reduction Values for On-Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of On-Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource On-Peak Hours in the month.

III.13.7.1.5.4.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. The summer seasonal Demand Reduction Value shall apply to the months of September, October, November, April and May.

III.13.7.1.5.4.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. The winter seasonal Demand Reduction Value shall apply to the months of February and March.

III.13.7.1.5.5. Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource Seasonal Peak Hours in the month. If there are no Demand Resource Seasonal Peak Hours in the months of July, August, or January, the Demand

Reduction Value for those months shall be equal to: (i) the Demand Reduction Value established for the previous month if the previous month's Demand Reduction Value was calculated using Seasonal Peak Hours or (ii) the Seasonal DR Audit results if the Demand Reduction Value for the previous month was not calculated using Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) where there was no audit conducted in the month, the applicable previous seasonal Demand Reduction Value.

III.13.7.1.5.5.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. This summer seasonal Demand Reduction Value will apply to the months of September, October, November, April and May.

III.13.7.1.5.5.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. This winter seasonal Demand Reduction Value will apply to the months of February and March.

III.13.7.1.5.6. [Reserved.]

III.13.7.1.5.6.1. [Reserved.]

III.13.7.1.5.6.2. [Reserved.]

III.13.7.1.5.7. Demand Reduction Values for Real-Time Demand Response Resources.

Demand Reduction Values are determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Demand Response Resource is the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of July, August, or January, the Demand Reduction Value of that resource for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous month's Demand Reduction Value was calculated using Real-Time Demand Response Event Hours or (ii)

the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Demand Response Event Hours. If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of June or December the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month.

III.13.7.1.5.7.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of a Real-Time Demand Response Resource for September, October, November, April and May shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Values in the most recent months of June, July and August and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of a Real-Time Demand Response Resource for February and March shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of December and January if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Value in the most recent months of December and January and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Demand Response Resource receiving a Dispatch Instruction for a Real-Time Demand Response Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Demand Response Resource's Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the

Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Demand Response Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.7.3.1. Determination of the Hourly Real-Time Demand Response Resource Deviation.

An Hourly Real-Time Demand Response Resource Deviation shall be calculated for each Real-Time Demand Response Resource as the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Demand Response Event Hour. The calculation of the Hourly Real-Time Demand Response Resource Deviation shall be determined in a manner that reflects that Real-Time Demand Response Resources are allowed 30 minutes from the beginning of the first Real-Time Demand Response Event Hour in consecutive Real-Time Demand Response Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in the Dispatch Instruction when such resources are dispatched in response to Real-Time Demand Resource Dispatch Hours. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Demand Response Resource Deviation is greater than zero in any Real-Time Demand Response Event Hour, the Hourly Real-Time Demand Response Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Load Zone in the hour or, starting on June 1, 2011, in the same Dispatch Zone in the hour.

III.13.7.1.5.8. Demand Reduction Values for Real-Time Emergency Generation Resources.

Demand Reduction Values shall be determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Emergency Generation Resource shall be the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous months Demand Reduction Value was calculated using Real-Time Emergency Generation Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Emergency Generation Event Hours. If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resource in that month.

III.13.7.1.5.8.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value for the months of September, October, November, April and May shall be equal to the simple average of the Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of September, October, November, April or May, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8, during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value for the months of February and March shall be equal to the simple average of the Demand Reduction Values in the most recent months of December and January if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of February or March, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8 during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Emergency Generation Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Emergency Generation Resource receiving a Dispatch Instruction for a Real-Time Emergency Generation Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Emergency Generation Resource's Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Emergency Generation Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.8.3.1. Determination of the Hourly Real-Time Emergency Generation Resource Deviation.

An Hourly Real-Time Emergency Generation Resource Deviation shall be calculated for each Real-Time Emergency Generation Resource as the difference between the Average Hourly Output or Average Hourly Load Reduction of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Emergency Generation Event Hour. The calculation of the Hourly Real-Time Emergency Generation Resource Deviation shall be determined in a manner that reflects that Real-Time Emergency Generation Resources are allowed 30 minutes from the beginning of the first Real-Time Emergency Generation Event Hour in consecutive Real-Time Emergency Generation Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in a Dispatch Instruction. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency

Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Emergency Generation Resource Deviation is greater than zero in any Real-Time Emergency Generation Event Hour, the Hourly Real-Time Emergency Generation Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Dispatch Zone in the hour.

III.13.7.1.5.9. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources and Real-Time Emergency Generation Resources Starting with the Capacity Commitment Period beginning June 1, 2012.

Starting with the Capacity Commitment Period beginning June 1, 2012, the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3, which is equal to the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, shall be eliminated from the determination of Hourly Calculated Demand Resource Performance Values, with the exception of Demand Resources that cleared in the Forward Capacity Auctions for the Capacity Commitment Periods beginning June 1, 2010 and June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared. For Demand Resources with such multi-year Capacity Supply Obligations the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3 shall continue to apply until the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

~~**III.13.7.1.5.10. Demand Response Capacity Resources.**~~

~~The performance of a Demand Response Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as defined in Section III.13.7.1.1.1. A Demand Response Capacity Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1). For the portion associated with the ability to reduce load at the Retail Delivery Point, availability for Demand Response Capacity Resources would be~~

adjusted for average avoided peak transmission and distribution losses as described in Section III.13.7.1.5.1 and Section III.13.7.1.5.1.1. For the portion associated with the ability to provide Net Supply, availability for Demand Response Capacity Resources would not be adjusted for average avoided peak transmission and distribution losses.

III.13.7.1.5.10.1 — Hourly Available MW.

A Demand Response Capacity Resource's available MW in each hour that contains any portion of a Shortage Event shall be determined based upon the sum of its associated Demand Response Resources as follows, provided, that in no case shall a Demand Response Capacity Resource's available MW in an hour exceed that resource's Qualified Capacity from the Forward Capacity Auction for the current Capacity Commitment Period per Section III.13.1.4.1. For purposes of the following calculations, when the output of a Real Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the calculated demand reduction of the Demand Response Asset measured at the Retail Delivery Point shall be reduced by the Real Time Emergency Generation Asset's output.

(a) — For a Demand Response Resource that produces a demand reduction and is following Dispatch Instructions where the Desired Dispatch Point for the Demand Response Resource is less than the Maximum Reduction and greater than or equal to the Minimum Reduction, the available MW in an hour shall be the greater of (i) the resource's Real Time Demand Reduction Obligation and (ii) the lesser of the resource's Demand Response Baseline as adjusted pursuant to Section III.8B.5 plus the Net Supply Limit, the resource's Hourly Adjusted Audited Demand Reduction, or the resource's Maximum Reduction as submitted or redeclared by the Lead Market Participant for the resource.

(b) — For a Demand Response Resource that produces a demand reduction and is following Dispatch Instructions where the Desired Dispatch Point for the Demand Response Resource is equal to the Maximum Reduction or the Desired Dispatch Point for the Demand Response Resource is less than the Minimum Reduction, the available MW in an hour shall be the resource's Real Time Demand Reduction Obligation plus any associated Net Supply.

(c) — For a Demand Response Resource that has produced a demand reduction but is not following Dispatch Instructions where the Real Time Demand Reduction Obligation is less than the Desired Dispatch Point for the Demand Response Resource, the available MW in an hour shall be the resource's Real Time Demand Reduction Obligation for the hour.

(d) — For a Demand Response Resource that has produced a demand reduction but is not following Dispatch Instructions where the Real Time Demand Reduction Obligation is greater than the Desired Dispatch Point for the Demand Response Resource, the available MW in an hour shall be the lesser of the resource's Real Time Demand Reduction Obligation and Hourly Adjusted Audited Demand Reduction for the hour.

(e) — For a Demand Response Resource that is not producing a demand reduction, is available for dispatch and is able to respond to Dispatch Instructions, and has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) and an Audited Full Reduction Time (adjusted for the Maximum Reduction) of thirty minutes or less, the available MW in an hour shall be the lesser of the resource's (i) Maximum Reduction, as submitted or redeclared by the Lead Market Participant, (ii) Actual Load plus the Net Supply Limit) or (iii) Hourly Adjusted Audited Demand Reduction.

(f) — For a Demand Response Resource that is not producing a demand reduction, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction as submitted or redeclared by the Lead Market Participant) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than thirty minutes and less than or equal to 12 hours, the available MW shall be zero unless the duration of the Shortage Event exceeds the Audited Full Reduction Time (adjusted for the Maximum Reduction) and Offered Full Reduction Time (adjusted for the Audited Demand Reduction), in which case the available MW in an hour shall be the lesser of (i) the resource's Maximum Reduction, as submitted or redeclared by the Lead Market Participant, (ii) the resource's Actual Load plus its New Supply Limit or (iii) the resource's Hourly Adjusted Audited Demand Reduction time weighted to reflect the portion of the hour in which the Demand Response Resource Notification Time and Demand Response Resource Start Up Time exceeded the Shortage Event duration.

(g) — For a Demand Response Resource that (i) is not producing a demand reduction, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than 12 hours or (ii) is unavailable to reduce demand, the available MW shall be zero.

III.13.7.1.5.10.1.1 — Adjusted Audited Demand Reduction.

~~A Demand Response Resource's Adjusted Audited Demand Reduction shall be determined as follows. For purposes of these calculations, when the output of a Real Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Maximum Reduction shall be reduced by the difference between the Real Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset:~~

~~(a) — A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) equal to its Audited Full Reduction Time (adjusted for the Maximum Reduction) shall have its Adjusted Audited Demand Reduction set equal to the resource's Audited Demand Reduction.~~

~~(b) — A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than its Audited Full Reduction Time (adjusted for the Maximum Reduction) shall have its Adjusted Audited Demand Reduction calculated as:~~

~~———— ((the Audited Full Reduction Time adjusted for the Maximum Reduction) divided by (the Offered Full Reduction Time adjusted for the Audited Demand Reduction)) multiplied by the lesser of the Audited Demand Reduction or Maximum Reduction as submitted or redeclared by the Lead Market Participant.~~

~~(c) — A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) less than its Audited Full Reduction Time (adjusted for the Maximum Reduction) shall have its Adjusted Audited Demand Reduction calculated as:~~

~~———— ((the Offered Full Reduction Time adjusted for the Audited Demand Reduction) divided by (the Audited Full Reduction Time adjusted for the Maximum Reduction)) multiplied by the lesser of the Audited Demand Reduction or Maximum Reduction as submitted or redeclared by the Lead Market Participant.~~

~~**III.13.7.1.5.10.1.2 — Hourly Adjusted Audited Demand Reduction.**~~

~~The Hourly Adjusted Audited Demand Reduction shall be calculated as the time weighted average of the Adjusted Audited Demand Reduction and Audited Demand Reduction for the period the resource was dispatched.~~

~~**III.13.7.1.5.10.2 — Availability Adjustments.**~~

~~The hourly availability score of a Demand Response Capacity Resource shall be increased in the same manner as described in Section III.13.7.1.1.4(a). The hourly availability score of a Demand Response Capacity Resource comprised of an aggregation of one or more Demand Response Resources shall be adjusted as described in Section III.13.7.1.1.4(b). In the case of Demand Response Resources comprised of an aggregation of one or more Demand Response Assets with a demand reduction and any Net Supply of less than 5 MW achieved by the asset in the most recent seasonal audit of the associated Demand Response Resource, a planned outage of the equipment used to produce the demand reduction scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource's hourly availability score as described in Section III.13.7.1.1.4(b).~~

~~In addition, the hourly availability score of a Demand Response Capacity Resource shall be increased as described in this subsection:~~

~~(a) — A Demand Response Capacity Resource's hourly availability score shall be increased, subject to verification by the ISO, when one or more Demand Response Assets of a Demand Response Resource associated with the Demand Response Capacity Resource is on a forced curtailment or scheduled curtailment.~~

~~(i) — A forced curtailment can be submitted to the ISO as described in the ISO New England Manuals for any reductions in demand that occur as a result of actions outside the control of the Demand Response Asset that is subject to the forced curtailment. The forced curtailment can be submitted or revised during the resettlement process and cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response Resource.~~

~~(ii) — A scheduled curtailment must be submitted to the ISO at least seven calendar days ahead of the start of the curtailment to be eligible for an adjustment for any reductions in load that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Demand Response Assets with a Maximum Interruptible Capacity of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start~~

~~of the curtailment. The scheduled curtailment cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response Resource. Scheduled curtailments must be a minimum of a single calendar day, and shall not exceed a total of 14 calendar days per Capacity Commitment Period.~~

~~(b) The sum of the availability adjustments for an hour may not exceed:~~

~~(i) for a Demand Response Resource that has received a Dispatch Instruction to reduce its demand, the lesser of (x) the resource's Demand Response Baseline as adjusted pursuant to Section III.8B.5 and (y) Audited Demand Reduction adjusted down by the greater of (1) the Maximum Reduction, as submitted or redeclared by the Lead Market Participant, or (2) Real-Time Demand Reduction Obligation. For purposes of this calculation, when the output of a Real-Time Emergency Generation Asset at the same location exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point, any Net Supply and the Maximum Reduction of the Demand Response Asset shall be reduced by the difference between the Real-Time Emergency Generation Asset's output and adjusted Demand Response Baseline of the Demand Response Asset.~~

~~(ii) for a Demand Response Resource that has not received a Dispatch Instruction to reduce its demand, the lesser of (i) the resource's Actual Load plus Net Supply Limit, or (ii) the Audited Demand Reduction adjusted down by (the Maximum Reduction, as submitted or redeclared by the Lead Market Participant.~~

III.13.7.1.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources are subject to the availability penalties and credits as defined by their resource type.

III.13.7.2. Payments and Charges to Resources.

Resources acquiring or shedding a Capacity Supply Obligation shall be subject to payments and charges in accordance with this Section III.13.7.2. Such resources will also be subject to adjustments as detailed in Section III.13.7.2.7.

III.13.7.2.1. Generating Capacity Resources.

III.13.7.2.1.1. Monthly Capacity Payments.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

(a) **Forward Capacity Auction.** For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case described in Section III.13.7.1.1.3(i), the lesser of the resource's Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted pursuant to Section III.13.2.7.3(b) (or in the case of Inadequate Supply or Insufficient Competition, the payment rate applicable to that resource under Section III.13.2.8) and as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below (the "FCA Payment"). For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

III.13.7.2.2. Import Capacity.

Import Capacity Resources shall receive monthly capacity payments utilizing the same methodology as that used for Generating Capacity Resources set forth in Section III.13.7.2.1.

III.13.7.2.2.A. Export Capacity.

If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

Charge Amount to Resource Exporting = [Capacity Clearing Price_{location of the interface} - Capacity Clearing Price_{location of the resource}] x Cleared MWs of Export Bid or Administrative Export De-List Bid]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located = [Capacity Clearing Price_{location of the interface} - Capacity Clearing Price_{location of the resource}] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.3.1.

III.13.7.2.3. Intermittent Power Resources.

An Intermittent Power Resource shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section 13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Power Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.4. Settlement Only Resources.

III.13.7.2.4.1. Non-Intermittent Settlement Only Resources.

Non-Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1.

III.13.7.2.4.2. Intermittent Settlement Only Resources.

Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Settlement Only Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.5. Demand Resources.

III.13.7.2.5.1. Monthly Capacity Payments for All Resources Except Real-Time Emergency Generation Resources.

For all Demand Resources except for Real-Time Emergency Generation Resources, the monthly payment shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1.

III.13.7.2.5.2. Monthly Capacity Payments for Real-Time Emergency Generation Resources.

For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f).

III.13.7.2.5.3. Energy Settlement for Real-Time Demand Response Resources

A Market Participant with Real-Time Demand Response Assets associated with a Real-Time Demand Response Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E1.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Demand Response Resource is located. The demand reduction paid or charged shall be net of the Real-Time Demand Reduction Obligation of Real-Time Demand Response Assets that are part of the Real-Time Demand Response Resource that received payment pursuant to Sections III.E1.9.2.1 or III.E1.9.2.2 for the same dispatch or audit period. Demand reductions eligible for payments or charges pursuant to

this section shall be those produced during Real-Time Demand Response Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4. Energy Settlement for Real-Time Emergency Generation Resources

A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions or generator output, adjusted as described in Section III.E1.8.3 or III.13.7.2.5.4.1 and for the percent average avoided peak distribution losses for the portion of the asset reducing demand, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing prior to June 1, 2018⁷, and at the Real-Time LMP for the Dispatch Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing on or after June 1, 2018⁷. Demand reductions or generator output eligible for payments or charges pursuant to this section shall be those produced during Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4.1 Adjustment for Net Supply From Real-Time Emergency Generation Assets.

For Capacity Commitment Periods commencing on or after June 1, 2018⁷, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the demand reduction measured at the Retail Delivery Point is first credited to the output of the Real-Time Emergency Generation Asset starting with the Net Supply amount, and any remaining demand reduction is credited to the Demand Response Asset. The Net Supply amount shall not be multiplied by one plus the average avoided peak distribution losses. The demand reduction amount shall be multiplied by one plus the average avoided peak distribution losses.

III.13.7.2.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources shall not receive monthly capacity payments for the portion of the resource designated as a Self-Supplied FCA Resource. Charges to load associated with Self-Supplied FCA Resources are calculated pursuant to Section III.13.7.3.

III.13.7.2.7. Adjustments to Monthly Capacity Payments.

Monthly capacity payments to resources with a Capacity Supply Obligation as of the beginning of the Obligation Month will be adjusted as described in Section III.13.7.2.7.1.

III.13.7.2.7.1. Adjustments to Monthly Capacity Payments of Generating Capacity Resources.

III.13.7.2.7.1.1. Peak Energy Rents.

For Capacity Commitment Periods beginning prior to June 1, 2019, payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents (“PER”) calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone.

III.13.7.2.7.1.1.1. Hourly PER Calculations.

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour (“Hourly PER”) equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

$$\text{Hourly PER}(\$/\text{kW}) = [(\text{LMP} - \text{Strike Price}) * [\text{Scaling Factor}] * [\text{Availability Factor}]]$$

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.2.7.1.1.2. Monthly PER Application.

(a) The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as follows:

PER Adjustment = the minimum of: (i) the PER cap or (ii) the Average Monthly PER x PER Capacity Supply Obligation.

Where the PER cap for each resource equals the FCA Payment plus the product of the (1) the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same Capacity Commitment Period and (2) the Capacity Clearing Price as adjusted in Section III.13.2.7.3(b) (or in the case of Inadequate Supply or Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing

Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8) applicable to that resource's location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation calculation.

- (b) PER shall be deducted from capacity payments independently of availability penalties.
- (c) FCA Payment minus PER may not be negative for any month.

III.13.7.2.7.1.2. Availability Penalties.

Availability penalties shall be assessed for each resource with a Capacity Supply Obligation as of the beginning of the Obligation Month. The penalty will be based on the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply or Insufficient Competition, on the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8 in the Capacity Zone in which the resource is located for the relevant Capacity Commitment Period, regardless of whether the resource assumed the Capacity Supply Obligation through a Forward Capacity Auction, a reconfiguration auction, or a Capacity Supply Obligation Bilateral.

For capacity resources that are partially or fully unavailable during a Shortage Event:

- (a) Penalties shall be determined and assessed on a resource-specific basis. Penalties shall be calculated for each Shortage Event during an Obligation Month and assessed on a monthly basis, subject to the availability penalty caps outlined in Section III.13.7.2.7.1.3.
- (b) The penalty per resource for each Shortage Event shall be equal to:
Penalty = [Resource's Annualized FCA Payment]*PF*[1 – Shortage Event Availability Score]

Where:

Annualized FCA Payment = the relevant Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply or Insufficient Competition, the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, multiplied by the resource's Capacity Supply Obligation as of the beginning of the Obligation Month multiplied by 12.

PF = .05 for Shortage Events of 5 hours or less. PF is increased by .01 for each additional hour above 5 hours.

III.13.7.2.7.1.3. Availability Penalty Caps.

The following caps will apply to the total availability penalties assessed to a resource. If a resource with a Capacity Supply Obligation sheds or acquires an obligation outside the relevant Obligation Month, the Annualized FCA Payment shall not be prorated. Caps are resource-specific and partial year assumption or transfer of a Capacity Supply Obligation through Capacity Supply Obligation Bilaterals or reconfiguration auctions does not affect the application of the cap to each resource independently.

- (a) **Per Day.** In no case shall the total penalties for all Shortage Events in an Operating Day exceed 10 percent of a resource's Annualized FCA Payment for that Capacity Commitment Period.
- (b) **Per Month.** The sum of a resource's penalties arising from unavailability during an Obligation Month may not exceed two and one-half times the Annualized FCA Payment, divided by twelve, for that Obligation Month. The sum of a resource's penalties arising from unavailability due to a single outage of four days or less but spanning two calendar months may not exceed two and one-half times the average of the Annualized FCA Payments, divided by twelve, for both months.
- (c) **Per Capacity Commitment Period.** In determining the availability penalties for the Obligation Month, a resource's cumulative availability penalties for a Capacity Commitment Period may not exceed its Annualized FCA Payment (less PER adjustments) for that Capacity Commitment Period.

III.13.7.2.7.1.4. Availability Credits for ~~Capacity Demand Response Capacity Resources,~~ Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources.

On a monthly basis, penalties received from unavailable resources shall be redistributed to ~~Demand Response Capacity Resources,~~ Generating Capacity Resources and Import Capacity Resources with Capacity Supply Obligations and to designated Supplemental Capacity Resources without a Capacity Supply Obligation that have a valid Supplemental Availability Bilateral (pursuant to Section III.13.5.3.2) that were available (pursuant to Section III.13.7.1.1.3, ~~Section III.13.7.1.5.10.1~~) in the respective hours on a Capacity Zone basis as follows: For each Obligation Month, the penalties assessed for the Shortage Events during the month will be credited to those resources identified above that were available, in whole or in part, during the Shortage Events, pro-rata by hourly available MW in the relevant Capacity Zones. Self-Supplied FCA Resources shall be eligible to receive their pro rata share of availability penalties paid by other capacity resources.

III.13.7.2.7.2. Import Capacity.

In addition to the adjustment in this section, Import Capacity Resources shall also be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.2.1. External Transaction Offer and Delivery Performance Adjustments.

In the event that the conditions in Section III.13.6.1.2.1 are not met in any hour of an Operating Day, the Import Capacity Resource will be subject to the following:

(a) If in any hour of an Operating Day a priced External Transaction associated with an Import Capacity Resource with a Capacity Supply Obligation is offered above both the offer threshold for the Operating Day and the offer threshold of the prior Operating Day, and for any priced External Transactions from the New York Control Area also is offered above the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of (1) the Import Capacity Resource's Capacity Supply Obligation and (2) the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), or in the case of Inadequate Supply or Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, divided by the number of days in the month.

(b) For every hour of an Operating Day that the total amount offered from all External Transactions associated with an Import Capacity Resource is less than the Import Capacity Resource's Capacity Supply Obligation, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the (1) difference between the Capacity Supply Obligation and the total amount of energy offered for that hour and (2) the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), or in the case of Inadequate Supply or Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, divided by the number of hours in the month. For each Operating Day only the greater of the total penalties in either the Day-Ahead Energy Market or Real-Time Energy Market will be assessed. For the purposes of this section the total energy offered will be adjusted in accordance with Section III.13.7.1.1.4(b) for any amount that was unavailable due to an outage approved in the ISO's annual maintenance scheduling process.

(c) Except as specified in Section III.13.7.2.7.2.2, for every hour the total energy from an External Transaction associated with an Import Capacity Resource delivered in real-time to the New England Control Area is less than the energy requested, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of (1) the difference between the quantity requested and the quantity delivered and (2) the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), or in the case of Inadequate Supply of Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, divided by the number of hours in the month.

Any External Transaction associated with an Import Capacity Resource that is determined to be in economic merit during the next-hour scheduling process will be considered a requested transaction and the ISO may request all or a portion of each transaction.

A Market Participant's total penalty amount for a single Operating Day for each Import Capacity Resource shall be no more than the product of (1) the Import Capacity Resource's Capacity Supply Obligation and (2) the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), or in the case of Inadequate Supply of Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, divided by the number of days in the month.

Each Obligation Month the penalty amounts from all Market Participants with Import Capacity Resources will be allocated to all Market Participants based on their pro-rata share of Capacity Load Obligation within each Capacity Zone in the Obligation Month, with each Capacity Zone allocated an amount based on the pro-rata share of total capacity credits within each Capacity Zone.

III.13.7.2.7.2.2. Exceptions.

- a) No penalty will be assessed if the applicable external interface is fully loaded and the energy from an External Transaction that would otherwise be requested cannot flow. If the transfer capability of the applicable external interface is zero in the import direction it will be considered fully loaded for the purpose of this section.
- b) No penalty will be assessed if the delivered energy from a priced External Transaction associated with the New York Control Area is less than requested when the Real-Time Energy Market price at the source location (NYISO Location-Based Marginal Price) is higher than the Real-Time LMP at the associated External Node, provided that Operating Procedure No. 4 has not been declared due to a system-wide capacity deficiency.
- c) No penalty will be assessed during periods when the ISO has taken action to reduce import transactions due to a Minimum Generation Emergency condition or due to ramping constraints.
- d) No penalty will be assessed on the affected external interface during periods when minimum-flow or directional-flow constraints have occurred, when the ISO was unable to utilize the automated check-out processes for the external interface, or when in-hour curtailments have occurred.

III.13.7.2.7.3. Intermittent Power Resources.

Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.4. Settlement Only Resources.

III.13.7.2.7.4.1. Non-Intermittent Settlement Only Resources.

Non-Intermittent Settlement Only Resources are subject to the same PER adjustments and availability penalties as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.4.2. Intermittent Settlement Only Resources.

Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.5. Demand Resources.

~~Demand Response Capacity Resources shall be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.~~

III.13.7.2.7.5.1. Calculation of Monthly Capacity Variances.

For each month, the Monthly Capacity Variance of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be calculated by subtracting the Demand Resource's Capacity Supply Obligation for the month from the Demand Resource's monthly Capacity Value. If a Demand Resource's Monthly Capacity Variance is zero, the Demand Resource will not be subject to Demand Resource Performance Penalties or Demand Resource Performance Incentives.

III.13.7.2.7.5.2. Negative Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Demand Resource's Monthly Capacity Variance is a negative value, the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be subject to a Demand Resource Performance Penalty equal to the absolute value of the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply of Insufficient Competition, multiplied by the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, in the Forward Capacity Auction for the relevant Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price, (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply or Insufficient Competition, multiplied by the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8 in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section

III.13.2.3.3(f). If a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a negative value, the Demand Resource Performance Penalty for such a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be set according to the Capacity Clearing Price applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31, of the year preceding the Capacity Commitment Period applicable to the Demand Resource for the particular Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Demand Resource for the particular Capacity Commitment Period.

III.13.7.2.7.5.3. Positive Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource's Monthly Capacity Variance is a positive value, then the Demand Resource shall be eligible to receive a Demand Resource Performance Incentive based on the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply of Insufficient Competition, multiplied by the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, in the Forward Capacity Auction for the relevant Capacity Commitment Period, or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price, (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply of Insufficient Competition, multiplied by the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in

Section III.13.2.3.3(f), provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone. If a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a positive value, then the Demand Resource Performance Incentive for such a Demand Resource shall be set according to the Capacity Clearing Price applicable to the Demand Resource for the particular Capacity Commitment Period (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource for the particulate Capacity Commitment Period in effect as of December 31 of the year preceding the Capacity Commitment Period, provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone.

III.13.7.2.7.5.4. Determination of Net Demand Resource Performance Penalties and Demand Resource Performance Incentives.

Demand Resource Performance Penalties and Demand Resource Performance Incentives shall be determined for each Capacity Zone as follows: if the sum of the Demand Resource Performance Penalties in a month in a Capacity Zone is less than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone, then the total amount of Demand Resource Performance Penalties shall be paid on a pro-rata basis, based on the non-prorated Demand Resource Performance Incentives of each Demand Resource with a positive Monthly Capacity Variance. The total amount of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total amount of the Demand Resource Performance Penalties in the same month in that Capacity Zone.

The total of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total of the Demand Resource Performance Penalties in the same month in that Capacity Zone. If the total Demand Resource Performance Penalties in a month in a Capacity Zone exceeds the total Demand Resource Performance Incentives in the same month in that Capacity Zone, the difference shall not be collected from load serving entities in that Capacity Zone (the ultimate purchaser of capacity).

III.13.7.2.7.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied, but shall be subject to the availability penalties and caps applicable to their resource types.

III.13.7.3. Charges to Market Participants with Capacity Load Obligations.

A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7.2 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals), less PER adjustments for resources in the zone as defined in Section 13.7.2.7.1.1, adjusted for any Demand Resource Performance Penalties in excess of Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.4, and including any applicable export charges or credits as determined pursuant to Section III.13.7.2.2.A divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.

III.13.7.3.1. Calculation of Capacity Requirement and Capacity Load Obligation.

The ISO shall assign each load serving entity a Capacity Requirement prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals) plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period to

the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period. The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with pumping of pumped hydro generators, if the resource was pumping; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as an Asset Related Demand or discrete load asset and is exclusively related to an Alternative Technology Regulation Resource following AGC dispatch instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A load serving entity's Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the Capacity Zone's Capacity Requirement as calculated above and (ii) the ratio of the sum of the load serving entity's annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period to the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period.

A load serving entity's Capacity Load Obligation shall be its Capacity Requirement, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supply FCA Resource designations. A Capacity Load Obligation can be a positive or negative value. A Market Participant that is not a load serving entity shall have a Capacity Load Obligation equal to the net obligation resulting from Capacity Load Obligation Bilaterals, HQICC, and Self-Supply FCA Resource designations.

A Demand Resource's Demand Reduction Value will not be reconstituted into the load of the Demand Resource for the purpose of determining the Capacity Requirement for the load associated with the Demand Resource.

III.13.7.3.1.1. HQICC Used in the Calculation of Capacity Requirements.

In order to treat HQICCs as a load reduction, each holder of HQICCs shall have its Capacity Requirement in the Capacity Zone in which the HQ Phase I/II external node is located as specified in Section III.13.1.3 adjusted by its share of the total monthly HQICC amount.

III.13.7.3.1.2. Charges Associated with Self-Supplied FCA Resources.

The capacity associated with a Self-Supplied FCA Resource shall be treated as a credit toward the Capacity Load Obligation of the load serving entity so designated by such resources as described in Section III.13.1.6. The amount of Self-Supplied FCA Resources shall be determined pursuant to Section III.13.1.6.

III.13.7.3.1.3. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.3.2. Excess Revenues.

Revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.3.3.

III.13.7.3.3. Capacity Transfer Rights.

III.13.7.3.3.1. Definition and Payments to Holders of Capacity Transfer Rights.

The ISO shall create Capacity Transfer Rights ("CTRs") for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone's Net Regional Clearing Price and absolute value of each Capacity Zone's Capacity Load Obligations, as calculated in Section III.13.7.3.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER and for Demand Resource Performance Penalties net of Demand Resource Performance Incentives.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supply FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supply FCA Resources.

The value of CTRs specifically allocated pursuant to Sections III.13.7.3.3.2(c), III.13.7.3.3.4, and III.13.7.3.3.6 shall be calculated as the product of: (i) the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply or Insufficient Competition, the lower of (1) the Capacity Clearing Price, and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8 for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply or Insufficient Competition, minus the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8 for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. The value of the specifically allocated CTRs will be deducted from the associated Capacity Zone's portion of the CTR fund. The balance of the CTR fund will then be allocated to the load serving entities as set forth in Section III.13.7.3.3.2.

III.13.7.3.3.2. Allocation of Capacity Transfer Rights.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

- (a) **Connecticut Import Interface.** The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.
- (b) **NEMA/Boston Import Interface.** Except as provided in Section III.13.7.3.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.
- (c) **Maine Export Interface.** Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine Export Interface for as long as Casco Bay continues to pay to support the transmission upgrades. Each municipal utility entitlement holder of a resource constructed as a Pool-Planned Unit in Maine shall receive specifically allocated CTRs across the Maine Export Interface equal to the applicable seasonal claimed capability of its ownership entitlements in such unit as described in Section III.13.7.3.3.6. The balance of the CTR fund associated with the Maine Export Interface shall be allocated to load serving entities with a Capacity Load Obligation on the import-constrained side of the Maine Export Interface.

III.13.7.3.3.3. Allocations of CTRs Resulting From Revised Capacity Zones.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.3.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

- (a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained

Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.3.3.4. Specifically Allocated CTRs Associated with Transmission Upgrades.

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.3.3.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.3.3.2.

III.13.7.3.3.5. [Reserved.]

III.13.7.3.3.6. Specifically Allocated CTRs for Pool Planned Units.

In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive an initial allocation of CTRs equal to the applicable seasonal claimed capability of the ownership entitlements in such unit. Municipal utility entitlements are set as shown in the table below and are not transferrable.

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4	Summer (MW)	Winter (MW)
Nominal Summer (MW)	1155.001	1244.275	104.000	100.000	104.000	67.400	65.300	586.725		
Nominal Winter (MW)	1155.481	1244.275	119.000	116.000	119.000	87.400	85.300	608.575		
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%	58.26	63.73
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%	5.04	5.55
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%	2.93	2.37
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%	15.49	15.64
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%	10.40	11.07
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%	57.69	60.26
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%	82.98	92.77
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%	30.53	32.64
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%	4.53	5.22
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%	4.71	5.35
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	7.63	7.63
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%	5.81	6.61
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%	26.40	30.36
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%	17.01	19.33
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%	15.34	16.63
Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%	24.05	24.12

Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%	10.70	12.28
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%	11.67	13.63
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%	36.93	42.17
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%	21.48	24.45
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%	25.58	29.49
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.33	1.33
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%	4.82	5.53
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%	24.33	26.23
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	10.89	10.90
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%	6.60	7.38
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.25	1.25
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%	10.67	12.27
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%	6.97	7.99
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%	10.18	11.69
Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%	67.51	77.27

This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

III.13.7.3.4. Forward Capacity Market Net Charge Amount.

The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charge; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund; and (d) any applicable export charges.

SECTION III

MARKET RULE 1

APPENDIX E1

DEMAND RESPONSE

~~Appendix E1 applies to Capacity Commitment Periods commencing prior to June 1, 2017.~~

APPENDIX E1
DEMAND RESPONSE
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Appendix E1 applies to Capacity Commitment Periods commencing prior to June 1, 2018⁷.

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APPENDIX E1 DEMAND RESPONSE

1. Demand Response Registration

Appendix E1 applies to Capacity Commitment Periods commencing prior to June 1, 2018⁷.

A Market Participant may register a Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis to provide demand reductions during hours ending 0800 through 1800 on non-Demand Response Holiday weekdays subject to the following conditions:

- (a) the asset is able to produce at least 100 kW of demand reduction, and;
- (b) the metering and communication equipment associated with the asset meets the requirements specified in Section III.E1.2.

A Real-Time Demand Response Asset may consist of an aggregation of multiple end-use metered customers.

1.1 Registration Parameters

During the registration process, Market Participants must submit the following information for each Real-Time Demand Response Asset:

- (a) Maximum Interruptible Capacity;
- (b) Maximum Load, and;
- (c) Maximum Generation, for Real-Time Demand Response Assets that are comprised of Distributed Generation.

1.2 Restrictions on Real-Time Demand Response Asset Registration

A Market Participant may not register and must retire if previously registered a Real-Time Demand Response Asset that is comprised of:

- (a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;
- (b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

A Market Participant may not register an existing Generator Asset as a Real-Time Demand Response Asset for the purpose of submitting Demand Reduction Offers.

2. Metering and Communication

2.1 Interval Metering and Telemetry Requirements

The actual metered demand of each individual end-use customer facility that comprises a Real-Time Demand Response Asset must be measured using interval meters located at the individual end-use customer's retail delivery point and shall be reported to the ISO at an interval of five minutes. Actual metered demand submitted to the ISO shall not include average avoided peak distribution losses.

Interval meters required pursuant to Section III.E1.2.1 must meet the following requirements:

- (a) the interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes;
- (b) if the interval meter is the same meter used by the distribution company for billing purposes, the meter is a revenue-quality meter that is accurate within $\pm 0.5\%$, and;
- (c) if the interval meter is not the same meter used by the distribution company for billing purposes, the interval meter is either a revenue-quality meter that is accurate within $\pm 0.5\%$ or a non-revenue-quality meter with an overall accuracy of $\pm 2.0\%$. For each non-revenue-quality meter used, the Market Participant must, during the registration process, submit certification from the meter

manufacturer that the interval meter being used meets the $\pm 2.0\%$ accuracy threshold, and shall specify accuracy for the following parameters:

- i. current measurement;
- ii. voltage measurement;
- iii. A/D conversion, and;
- iv. calibration.

2.2 Meter Testing

All interval meters must be periodically tested and calibrated.

Market Participants must conduct periodic meter data validation checks.

Market Participants must repair or replace meters that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters and meter data communication systems.

2.3 Auditing

The ISO may, for a Real-Time Demand Response Asset, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and measurement equipment, and witness the demand reduction activities of any facility associated with the asset.

Market Participants must make retail billing meter data from the Host Participant for the facilities associated with a Real-Time Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing, and certifying the metering, data recording and measurement equipment of Real-Time Demand Response Assets.

2.4 Communication/Telemetry

Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facilities comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area. If one or more generators whose output can be controlled is located behind the retail delivery point of the Real Time Demand Response Asset, other than emergency generators that cannot operate synchronized to the electrical grid, then the Market Participant must also submit to the ISO in Real-Time a single set of interval meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

3. Demand Reduction Offers

3.1 Required Demand Reduction Offer Parameters

Market Participants must submit a Demand Reduction Offer for each Real-Time Demand Response Asset that meets the requirements of this section in order to be eligible for a demand reduction payment.

A Demand Reduction Offer must be equal to or greater than the Demand Reduction Threshold Price in effect on the day the Demand Reduction Offer is made.

Demand Reduction Offers reflect the amount of demand reduction offered at the retail delivery point excluding transmission and distribution losses.

A Demand Reduction Offer shall consist of a single offer price in \$/MWh (less than or equal to \$1000/MWh) and a single demand reduction amount (in MW to the nearest 0.1 MW) that shall apply to hours ending 0800 through 1800 in the Operating Day.

A Market Participant may submit a single Demand Reduction Offer for each of its Real-Time Demand Response Assets for each Operating Day that is a non-Demand Response Holiday weekday.

Demand Reduction Offers for the following Operating Day must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the Operating Day and may not be changed thereafter.

The minimum Demand Reduction Offer amount for each Real-Time Demand Response Asset is 100 kW.

The maximum Demand Reduction Offer amount for each Real-Time Demand Response Asset cannot exceed the asset's Maximum Interruptible Capacity.

Market Participants are prohibited from submitting a Demand Reduction Offer for a Real-Time Demand Response Asset for an Operating Day with a scheduled curtailment, or for an Operating Day with a known forced curtailment. If an unanticipated forced curtailment has occurred, Market Participants are prohibited from submitting a Demand Reduction Offer for the affected Real-Time Demand Response Asset for any subsequent Operating Days until the forced curtailment is over and electrical service to the asset has been restored.

3.2 Optional Demand Reduction Offer Parameters

A Demand Reduction Offer may specify a minimum interruption duration of one to four hours. If a Market Participant does not specify a minimum interruption duration in its Demand Reduction Offer, the minimum interruption duration shall be one hour.

A Demand Reduction Offer may specify a curtailment initiation price (in \$ per interruption). If a Market Participant does not specify a curtailment initiation price, the curtailment initiation price shall be \$0.

A Demand Reduction Offer must meet the following minimum and maximum price requirements:

- (a) The offer price not including the curtailment initiation price shall be greater than or equal to the Demand Reduction Threshold Price; and

(b) The offer cost of the Demand Reduction Offer, which shall include the curtailment initiation price, shall be less than or equal to \$1000/MWh. The offer cost shall be computed as follows: offer cost = offer price + [curtailment initiation price/(minimum interruption duration x bid amount (MW))].

4. Day-Ahead Clearing, Scheduling and Notification

Demand Reduction Offers are cleared after the Day-Ahead Energy Market results are determined.

Demand Reduction Offers are cleared by comparing the Demand Reduction Offer to the hourly Day-Ahead LMPs for the Load Zone in which the Real-Time Demand Response Asset is located. A Demand Reduction Offer associated with a Real-Time Demand Response Asset will clear in one or more hours of the Operating Day if the sum of the hourly Day-Ahead LMP times the Demand Reduction Offer amount in the cleared hours of the Operating Day is greater than or equal to the sum of the curtailment initiation price for the Operating Day and the sum of the Demand Reduction Offer price times the Demand Reduction Offer amount in the cleared hours of the Operating Day.

The ISO will provide Market Participants with demand curtailment schedules for Real-Time Demand Response Assets based on cleared Demand Reduction Offers.

The demand curtailment schedule shall reflect demand reductions (MW) at the Real-Time Demand Response Asset's retail delivery point.

5. Real-Time Scheduling of Demand Reductions

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for the next Operating Day pursuant to Section III.E1.4. If a Market Participant's Demand Reduction Offer is not cleared Day-Ahead to reduce demand in an hourly time interval for the next Operating Day, the Market Participant may initiate a Real-Time demand reduction by reducing demand when the offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which a Real-Time Demand Response Asset is located.

A Market Participant will not receive a Dispatch Instruction in Real-Time for a Real-Time Demand Response Asset.

5.1 Requirements for Demand Reductions of 5 MW and Above

A Market Participant with a Real-Time Demand Response Asset that has submitted a Demand Reduction Offer for the Operating Day, must request permission from the ISO prior to reducing demand in an amount greater than or equal to 5 MW during a 60 minute period, unless the asset was dispatched or audited pursuant to Section III.13. Permission must be requested not less than 15 minutes and not greater than 60 minutes before the start of the demand reduction. The ISO may approve or deny the requested interruption based on the impact of the interruption on system reliability.

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data for the same month of the previous year. The ISO may adjust the offer data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

- i. Each generator and import offer block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.
- ii. An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer block.
- iii. A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.
- iv. A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from demand response exceeds the cost to load associated with compensating demand response.
- v. The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} \times \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the resulting Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the preceding month in advance of the Demand Reduction Threshold Price's effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Real-Time Demand Response Assets located anywhere within the New England Control Area.

7. Demand Response Baselines

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8A prior to submitting a Demand Reduction Offer for a Real-Time Demand Response Asset.

A Market Participant shall take no actions to establish a Demand Response Baseline or affect a Demand Response Baseline adjustment that results in a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers absent demand reduction payments.

For Real-Time Demand Response Assets comprised of Distributed Generation, a Market Participant shall take no actions to establish a Demand Response Baseline that results in a Demand Response Baseline that reduces the expected output levels of its generation absent demand reduction payments.

8. Real-Time Demand Reduction Obligations

8.1 Real-Time Demand Reduction of Assets Without Generation

The Real-Time demand reduction amount of a Real-Time Demand Response Asset is equal to the difference between its Demand Response Baseline adjusted pursuant to Section III.8A.4 and the asset's Real-Time metered demand, during the intervals that the Real-Time Demand Response Asset was scheduled Day-Ahead by the ISO to reduce demand or was otherwise eligible to receive payment for a demand reduction in Real-Time. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered demand is greater than its adjusted Demand Response Baseline.

8.2 Real-Time Demand Reduction of Assets With Generation

To the extent a generator is located behind the retail delivery point of an individual end-use customer facility that comprises a Real-Time Demand Response Asset, the metered output of the generator in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline. The Real-Time demand reduction amount achieved by the individual end-use customer facility that comprises a Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval minus the sum of the metered demand measured at the retail delivery point and the output of all of the generators located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of all of the generators is greater than its adjusted Demand Response Baseline.

If a Real-Time Demand Response Asset is comprised of a Distributed Generation asset located behind the retail delivery point of an individual end-use customer facility, the interval metered output of the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be used to determine its Demand Response Baseline. The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be equal to the asset's incremental output in each five-minute interval relative to its Demand Response Baseline in the same intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered output is less than its Demand Response Baseline.

8.2.1 Real-Time Demand Reduction of Assets With Generation But With No Other Real-Time Demand Response Asset at that Location

For a Real-Time Demand Response Asset located at a retail delivery point with no other Real-Time Demand Response Assets at or behind the same retail delivery point, the metered output of any Real-Time Emergency Generation Assets in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline.

The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval, calculated pursuant to Section III.8A.4.4, minus the sum of the metered demand measured at the retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of any Real-Time Emergency Generation Assets is greater than its adjusted Demand Response Baseline.

8.3 Treatment of Net Supply

If the metered amount measured at the retail delivery point reflects net energy supply during intervals in which Real-Time Demand Response Assets and/or Real-Time Emergency Generation Assets behind the retail delivery point had positive Real-Time demand reductions, then the amount of net energy supplied in an interval with a positive Real-Time demand reduction shall be subtracted from the Real-Time demand reduction amount in the same interval of each Real-Time Demand Response Asset and/or Real-Time Emergency Generation Asset behind that retail delivery point on a *pro rata* basis. The adjustment for net energy supply shall not result in a negative Real-Time demand reduction amount.

8.4 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Real-Time Demand Response Asset is equal to its Real-Time demand reduction amount adjusted for net supply (limited to 200% of the associated Demand Reduction Offer amount) multiplied by one plus the percent average avoided peak distribution losses.

9. Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Real-Time Demand Response Asset will be paid for its Day-Ahead Demand – Reduction Obligation multiplied by the Day-Ahead LMP for the Load Zone within which the Real-Time Demand Response Asset is located.

9.2 Real-Time Settlement

9.2.1. Real-Time Demand Response Assets with Cleared Demand Reduction Offers

A Market Participant with a Real-Time Demand Response Asset will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the final hourly Real-Time LMP for the Load Zone within which the Real-Time Demand Response Asset is located. The payment for the amount by which the Real-Time Demand Reduction Obligation exceeds the Day-Ahead Demand Reduction Obligation in an hour shall be set to zero if the provisional Real-Time LMP for that hour is less than the Demand Reduction Threshold Price.

A Market Participant will not be charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E1.5.1.

9.2.2. Real-Time Demand Response Assets without Cleared Demand Reduction Offers

If the Demand Reduction Offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which the Real-Time Demand Response Asset is located, the Market Participant will be paid the final hourly Real-Time LMP multiplied by its Real-Time Demand Reduction Obligation.

A Market Participant will not be charged pursuant to Section III.E1.9.2.2 if:

- (a) a Demand Reduction Offer does not clear Day-Ahead pursuant to Section III.E1.4, and;

(b) the Real-Time Demand Response Asset produces a negative Real-Time demand reduction amount.

A Market Participant will not be paid for a Real-Time Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E1.5.1.

9.3 Cost Allocation

Payments and charges pursuant to this section will be allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes or incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

10. Average Distribution Losses

For purposes of Section III.E1, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

SECTION III

MARKET RULE 1

APPENDIX E2

DEMAND RESPONSE

~~Appendix E2 applies to Capacity Commitment Periods commencing on or after June 1, 2017.~~

APPENDIX E2
DEMAND RESPONSE
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Appendix E2 applies to Capacity Commitment Periods commencing on or after June 1, 2018⁷.

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**APPENDIX E2
DEMAND RESPONSE**

Appendix E2 applies to Capacity Commitment Periods commencing on or after June 1, 2018⁷.

1. Demand Response Registration

1.1 Demand Response Resource Registration

A Market Participant may register a Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis and providing Operating Reserve subject to the following conditions:

- (a) each Demand Response Resource must be a single Demand Response Asset or an aggregation of Demand Response Assets located within the same Dispatch Zone and Reserve Zone;
- (b) each Demand Response Resource must be able to produce at least 100 kW of demand reduction;
- (c) the Market Participant must comply with ISO required auditing and testing requirements; and
- (d) the Market Participant must indicate whether it intends to maintain CLAIM10 or CLAIM30 capability for the Demand Response Resource.

A Market Participant may not register a Real-Time Emergency Generation Resource, an On-Peak Demand Resource, a Seasonal Peak Demand Resource or a Dispatchable Asset Related Demand to participate as a Demand Response Resource in the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant may not register a Generator Asset as a Demand Response Asset for the purpose of submitting Demand Reduction Offers. A Market Participant may not register a Demand Response Asset at the same Retail Delivery Point as an existing Generator Asset, and may not register a Generator Asset at the same Retail Delivery Point as an existing Demand Response Asset; provided that this provision shall not apply if the Generator Asset is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

1.2 Demand Response Capacity Resource Registration

A Market Participant may register a Demand Response Capacity Resource subject to the following conditions:

- (a) each Demand Response Capacity Resource must have mapped to it at least one Demand Response Resource within the same Dispatch Zone in order to comply with the energy market offer requirements in Section III.13.6.1.5; and
- (b) a Demand Response Resource cannot be mapped to a Demand Response Capacity Resource, or maintain the mapping to a Demand Response Capacity Resource, if the Demand Response Resource violates the mapping provisions in Section III.E2.1.4(c).

1.3 Demand Response Asset Registration

A Market Participant may register a Demand Response Asset subject to the following conditions:

- (a) Unless it meets the conditions for aggregation in sub-section (b) below, a Demand Response Asset must have a defined, single Retail Delivery Point and be registered at a single Node.
- (b) A Demand Response Asset may be the aggregate demand reduction capability of multiple end-use customers from multiple delivery points within a single Dispatch Zone and Reserve Zone if (i) the demand reduction from each Retail Delivery Point in the aggregation is less than 10 kW, and (ii) the demand at the multiple Retail Delivery Points satisfy the criteria for a homogenous population. A Demand Response Asset that meets these conditions for aggregation must be registered at a single Dispatch Zone and Reserve Zone rather than at a single Node.
- (c) No more than one Demand Response Asset may be located at a single Retail Delivery Point.
- (d) Each Demand Response Asset must be mapped to a Demand Response Resource.
- (e) Each Demand Response Asset must be able to produce at least 10 kW of demand reduction.
- (f) A Demand Response Asset with a registered Maximum Interruptible Capacity equal to or greater than 5 MW from the same Retail Delivery Point must be registered as a single Demand Response Resource at a Node. The evaluation of whether a Demand Response Asset's Maximum Interruptible Capacity is equal to or greater than 5 MW shall account for the most recent seasonal audit results for the assets.
- (g) The metering and communication equipment associated with each Demand Response Asset must meet the requirements in Section III.E2.2.

During the registration process, Market Participants must submit the following for each Demand Response Asset:

- (a) Maximum Interruptible Capacity;
- (b) Maximum Load;
- (c) Maximum Generation, for Demand Response Assets that are comprised of Distributed Generation;
- (d) For a Demand Response Asset capable of producing Net Supply, the Maximum Net Supply permitted under the asset's interconnection agreement; and
- (e) Retail account number and meter number for the end-use customer.

1.4 Restrictions on Demand Response Resource Registration

A Market Participant may not register and must retire if previously registered a Demand Response Resource that is comprised of:

- (a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;
- (b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.
- (c) The Maximum Interruptible Capacity adjusted for the Audited Demand Reduction of each Demand Response Resource registered by a Market Participant within a single Dispatch Zone and Reserve Zone must be at least 1 MW before the Market Participant registers a new Demand Response Resource within that same Dispatch Zone and Reserve Zone. This restriction shall not apply if either:
 - (i) all Demand Response Assets registered by the Market Participant in the Dispatch Zone and Reserve Zone are mapped to a Demand Response Resource mapped to a Demand Response Capacity Resource and the Market Participant wants to register a Demand Response Resource that is not mapped to a Demand Response Capacity Resource; or
 - (ii) all Demand Response Assets registered by the Market Participant in the Dispatch Zone and Reserve Zone are mapped to a Demand Response Resource not mapped to a Demand Response Capacity Resource and the Market Participant wants to register a Demand Response Resource that is mapped to a Demand Response Capacity Resource.

(d) In the event the Audited Demand Reductions of two or more Demand Response Resources registered by a Market Participant within a single Dispatch Zone and Reserve Zone are less than 1 MW following an audit, Demand Response Asset mapping for that Market Participant shall be adjusted if doing so decreases the number of Demand Response Resources within that Dispatch Zone and Reserve Zone.

1.5 Restrictions on Demand Response Asset Mapping

Demand Response Assets may be un-mapped from a Demand Response Resource for re-mapping to another Demand Response Resource, or un-mapped without re-mapping, subject to the following conditions:

- (a) A Demand Response Asset cannot be unmapped from a Demand Response Resource that is mapped to a Demand Response Capacity Resource if, following the un-mapping, the sum of the demand reductions of the remaining Demand Response Assets that are associated with the Demand Response Capacity Resource, as reflected in the most recent seasonal audit for that resource, would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.
- (b) When a Demand Response Asset can be mapped to more than one Demand Response Resource that is mapped to a Demand Response Capacity Resource, a Demand Response Asset shall be mapped to a Demand Response Resource associated with a Demand Response Capacity Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period before being mapped to a Demand Response Resource associated with a non-commercial Demand Response Capacity Resource or non-commercial increment of a Demand Response Capacity Resource.
- (c) A Demand Response Asset may be re-mapped to another Demand Response Resource only if the Audited Full Reduction Time of the asset's new Demand Response Resource, adjusted for the Audited Demand Reduction of the asset's current Demand Response Resource, is equal to or greater than the Audited Full Reduction Time of the Demand Response Resource from which the Demand Response Asset is being un-mapped.
- (d) If a Demand Response Asset is re-mapped to a Demand Response Resource, and the Audited Full Reduction Time of the Demand Response Resource to which the asset is being mapped, adjusted for the Audited Demand Reduction of the Demand Response Resource from which

the asset is being mapped, is less than the Audited Full Reduction Time of the Demand Response Resource from which the asset is being mapped, the Demand Response Asset audit value will be set to zero.

2. Metering and Communication

2.1 Revenue Quality Interval Metering

The metered demand used for settlement purposes of each individual end-use customer facility that comprises a Demand Response Asset must be measured using interval meters located at the individual end-use customer's Retail Delivery Point and shall be reported to the ISO at an interval of five minutes. Metered demand data submitted to the ISO shall not include average avoided peak distribution losses.

The interval meters required pursuant to Section III.E2.2.1 must meet the following requirements:

- (a) The interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes;
- (b) The interval meter can be the same revenue-quality meter used by the distribution company for billing purposes; and
- (c) If the interval meter is not the same revenue-quality meter used by the distribution company for billing purposes, the Market Participant must validate and provide documentation to the ISO that the difference between the values recorded by the Market Participant's meter in each interval and the value recorded by the distribution company's billing meter in the same interval is within $\pm 2.0\%$; provided that, if accurate interval data from the distribution company are not available, the Market Participant shall validate that the difference between the sum of the values recorded by the Market Participant's meter and the sum of the values recorded by the distribution company's billing meter over the same time period is within $\pm 2.0\%$; and further provided that the Market Participant specifies the meter manufacturer and model, and the accuracy for the following parameters:
 - i. current measurement;
 - ii. voltage measurement;
 - iii. A/D conversion; and
 - iv. calibration.

- (d) The Market Participant shall provide documentation to the ISO of any inaccuracies found in distribution company meter data and of any communications with the distribution company to address the meter data inaccuracies.

2.2 Communication/Telemetry

Market Participants must report in Real-Time to the ISO a single set of telemetry data for each individual end-use customer facility that comprises a Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of the Demand Response Asset as measured at the Retail Delivery Point, and shall be reported to the ISO every five minutes. For a Demand Response Resource to provide Ten Minute Spinning Reserve or Ten Minute Non-Spinning Reserve, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

The Market Participant must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions.

If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of telemetry data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

The telemetry measurement device used to measure the real-time demand and any Net Supply pursuant to Section III.E2.2.2 must have an overall accuracy of $\pm 2.0\%$. If the Market Participant is not using the meter used by the distribution company for billing purposes to obtain the real-time telemetry, then the Market Participant must specify the device manufacturer and model, and submit certification from the

measurement device manufacturer that the device being used meets the $\pm 2.0\%$ accuracy threshold, and shall specify the accuracy for the following parameters:

- i. current measurement;
- ii. voltage measurement;
- iii. A/D conversion; and
- iv. calibration.

2.3 Testing of Meters and Telemetry Measurement Devices

All interval meters and telemetry measurement devices must be periodically tested and calibrated.

Market Participants must conduct periodic meter and telemetry data validation checks.

Market Participants must repair or replace meters or telemetry measurement devices that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters, telemetry measurement devices, and data communication systems.

2.4 Auditing

The ISO may, for Demand Response Resources, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset.

Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing and certifying the metering, data recording and telemetry measurement equipment of Demand Response Assets.

3. Day-Ahead Energy Market Demand Reduction Offers

Market Participants must submit a Demand Reduction Offer for each Demand Response Resource that meets the requirements of this section in order to be eligible for a payment for a demand reduction.

The Market Participant's Demand Reduction Offer for a Demand Response Resource must satisfy the following conditions:

- (a) Demand Reduction Offers must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the applicable Operating Day.
- (b) The Market Participant can submit up to 10 monotonically increasing price/demand reduction amount pairs for each Operating Day. The demand reduction amount shall not include an adjustment for average avoided peak transmission and distribution losses.
- (c) The minimum amount for each price/demand reduction amount pair of a Demand Reduction Offer is 100 kW.
- (d) The sum of all price/demand reduction amount pairs for a Demand Reduction Offer cannot exceed the sum of the Maximum Interruptible Capacities of the resource's Demand Response Assets.
- (e) The minimum Demand Reduction Offer price must be equal to or greater than the Demand Reduction Threshold Price in effect for the day the Demand Reduction Offer is submitted.
- (f) The maximum Demand Reduction Offer price must be less than or equal to the Energy Offer Cap.

Market Participants may not Self-Schedule interruptions in the Day-Ahead Energy Market.

3.1 Required Demand Reduction Offer Parameters

The Market Participant shall provide the following hourly values in its Demand Reduction Offer. The Market Participant shall maintain up-to-date values for each of these parameters prior to and throughout the Operating Day:

- (a) Available or Unavailable;
- (b) Minimum Reduction (MW), and;
- (c) Maximum Reduction (MW).

3.2 Optional Demand Reduction Offer Parameters

The Market Participant may also specify the following in its Demand Reduction Offer:

- (a) Interruption Cost (\$)
- (b) Minimum Reduction Time (Hrs)
- (c) Minimum Time Between Reductions (Hrs)
- (d) Demand Response Resource Start-Up Time (Hrs)
- (e) Demand Response Resource Notification Time (Hrs)
- (f) Demand Response Resource Ramp Rate (MW/min)
- (g) Offered CLAIM10 (MW)
- (h) Offered CLAIM30 (MW)

4. Real-Time Energy Market Demand Reduction Offers

During the Re-Offer Period, Market Participants may submit revisions to the price or demand reduction amount parameters of a Demand Reduction Offer. Demand Response Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices.

Revisions to Demand Reduction Offers during the Re-Offer Period are subject to the following conditions that apply to Day-Ahead Demand Reduction Offers under Section III.E2.3: limitation to 10 monotonically increasing price/demand reduction amount pairs, minimum amount, maximum amount, minimum price and maximum price.

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for that Operating Day pursuant to Section III.E2.5 or modified during the Re-Offer Period.

No changes will be allowed to the Demand Reduction Offer after the close of the Re-Offer Period. Market Participants may not Self-Schedule interruptions in the Real-Time Energy Market.

5. Scheduling and Dispatching

The ISO shall schedule in the Day-Ahead Energy Market and schedule and dispatch in the Real-Time Energy Market the Demand Response Resource as specified in Section III.1.7.6(a).

At the conclusion of the Day-Ahead Energy Market clearing, the ISO will provide Market Participants with Day-Ahead demand reduction schedules for Demand Response Resources reflecting demand reduction amounts that do not include average avoided peak transmission and distribution losses for each hour of the following Operating Day.

During the Operating Day, the ISO will issue Dispatch Instructions to the Market Participant specifying the expected demand reduction amount that does not include average avoided peak transmission and distribution losses from their Demand Response Resource and the Dispatch Rate.

A Market Participant must notify the ISO, as soon as practicable, of a facility or generator shutdown or equipment outage (including partial outages) that reduces the Demand Response Resource's ability to achieve the demand reduction reflected in the Demand Reduction Offer for an Operating Day.

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data for the same month of the previous year. The ISO may adjust the offer data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

- (a) Each generator and import offer block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.
- (b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer block.
- (c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

- (d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from demand response exceeds the cost to load associated with compensating demand response.
- (e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$D RTP = P_{th} \bar{A} \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the resulting Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the preceding month in advance of the Demand Reduction Threshold Price's effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Demand Response Resources located anywhere within the New England Control Area.

7. Real-Time Demand Reduction Obligation

A Demand Response Resource's Real-Time Demand Reduction Obligation will be calculated for each dispatch interval in which the Demand Response Resource receives a Dispatch Instruction to reduce demand.

7.1 Real-Time Demand Reductions

The Real-Time demand reduction in a dispatch interval is the difference between the adjusted Demand Response Baseline, further adjusted for any metered output for a Real-Time Emergency Generation Asset

located at the same Retail Delivery Point, and the metered demand for each Demand Response Asset associated with the Demand Response Resource.

If a Market Participant receives a Dispatch Instruction for a Demand Response Resource to reduce demand in a dispatch interval by zero MW, then in calculating the Real-Time Demand Reduction Obligation of the Demand Response Resource the Real-Time demand reductions of the Demand Response Assets comprising the resource shall be equal to zero for that dispatch interval.

7.2 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Demand Response Resource is the sum of the hourly integrated Real-Time demand reduction amounts of the Demand Response Assets comprising the Demand Response Resource, multiplied by one plus the percent average avoided peak distribution losses, except that any Net Supply produced by the Demand Response Assets comprising the Demand Response Resource will not be adjusted by average avoided peak distribution losses.

If a Market Participant fails to comply with the metering and communication requirements in Section III.E2.2 for a Demand Response Resource for any period of time, then the Real-Time Demand Reduction Obligation shall be zero for that period of time.

8. Demand Response Resource Baseline

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8B prior to submitting a Demand Reduction Offer for a Demand Response Resource, and must comply with the requirements for maintaining and resetting the Demand Response Baseline as set forth in Section III.8B.

A Market Participant shall not take actions to create or maintain a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers in the absence of demand reduction payments.

9. Energy Market Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Demand Response Resource will be paid for its Day-Ahead Demand Reduction Obligation multiplied by the Day-Ahead LMP for the Dispatch Zone or Node at which the resource is registered.

9.2 Real-Time Settlement

A Market Participant with a Demand Response Resource will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the hourly Real-Time LMP for the Dispatch Zone or Node at which the resource is registered.

9.3 Cost Allocation

Charges or payments resulting from Real-Time demand reductions produced by Demand Response Resources or Real-Time Emergency Generation Resources shall be allocated on an hourly basis proportionally to Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

9.4 NCPC Credits and Charges

A Market Participant with a Demand Response Resource is eligible for NCPC credits if the resource is following Dispatch Instructions. A Market Participant with a Demand Response Resource is ineligible for NCPC credits and may be assessed NCPC charges if the resource is not operating within the acceptable dispatch tolerance. A resource is not operating within the acceptable dispatch tolerance if in any five-minute interval for an hour the resource is not operating within 10% above or below the resource's Dispatch Instruction, except that a Market Participant with a resource that is not operating within the acceptable dispatch tolerance will not be assessed NCPC charges if during the entire hour the resource operates within 5% above or below the resource's Dispatch Instruction.

10. Average Avoided Peak Distribution Losses

For purposes of Section III.E2, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

- (a) words denoting the singular include the plural and vice versa;
- (b) words denoting a gender include all genders;
- (c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;
- (d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;
- (e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;
- (f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;
- (g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;
- (h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;
- (i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;
- (j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

other late payment or charge, provided such payment is made on such next succeeding Business Day);

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

I.2.2. Definitions:

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

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

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

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

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

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity's right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource is any Resource eligible to provide Regulation that is not registered as a different Resource type.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annualized FCA Payment is used to determine a resource's availability penalties and is calculated in accordance with Section III.13.7.2.7.1.2(b) of Market Rule 1.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

APR-1 means the first of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-2 means the second of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-3 means the third of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

Asset is a generating unit, interruptible load, a component of a demand response resource or load asset.

Asset Registration Process is the ISO business process for registering a physical load, generator, or tie-line for settlement purposes. The Asset Registration Process is posted on the ISO's website.

Asset Related Demand is a physical load that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of one or more individual end-use metered customers receiving service from the same point or points of electrical supply, with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of “unavailable” for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of “available,” the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net risk-adjusted going forward costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Audited Demand Reduction is the seasonal claimed capability of a Demand Response Resource as established pursuant to Section III.13.6.1.5.4.

Audited Full Reduction Time is the Offered Full Reduction Time associated with the Demand Response Resource’s most recent audit.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a generating unit change its output while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (iv) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure

consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart CIP Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 utilizing data from Table 6 of Appendix A to this Schedule 16, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Blackstart Station's costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Blackstart CIP O&M Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a Blackstart Station's operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision of Blackstart Service.

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual compensation, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, for a Designated Blackstart Resource's operating and maintenance costs associated with the provision of Blackstart Service (except for operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT, which also encompasses "System Restoration and Planning Service" under the predecessor version of Schedule 16.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating

Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Station-specific Rate CIP Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5)

with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (for Capacity Commitment Periods commencing on or after June 1, 2018, Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capability Year means a year's period beginning on June 1 and ending May 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on July 14, 2014.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Clearing Price Floor is described in Section III.13.2.7.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible, equal to that Market Participant's Capacity Requirement (if any) adjusted to account for any relevant Capacity Load Obligation Bilaterals, as described in Section III.13.7.3.1 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on July 14, 2014.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Requirement is described in Section III.13.7.3.1 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in the rules filed with the Commission on January 17, 2014, and accepted by the Commission on May 30, 2014.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Right (CTR) is a financial right that entitles the holder to the difference in the Net Regional Clearing Prices between Capacity Zones for which the transfer right is defined, in the MW amount of the holder's entitlement.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Value is the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.7.1.5 of Market Rule 1.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Category A Designated Blackstart Resource is a Designated Blackstart Resource that has committed to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 and has not been converted to a Category B Designated Blackstart Resource.

Category B Designated Blackstart Resource is a Designated Blackstart Resource that is not a Category A Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each power year, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset in all Load Zones. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.A of that policy.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer

paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

- (1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and
- (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry (\$/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailed is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(iii) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2018, Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts of a Demand Response Resource scheduled by the ISO as a result of the Day-Ahead Energy Market, multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1 and purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2018.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(ii) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(i) of Market Rule 1.

Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Program. The Day-Ahead Load Response Program allows Market Participants with registered Load Response Program Assets to make energy reduction offers into the Day-Ahead Load Response Program concurrent with the Day-Ahead Energy Market.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(iv) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(h) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(g) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2018, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.E1.6 and Section III.E2.6.

Demand Reduction Value is the quantity of reduced demand calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

Demand Resource is a resource defined as Demand Response Capacity Resources, On-Peak Demand Resources, Seasonal Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area pursuant to Appendix III.E1 and Appendix III.E2 of Market Rule 1, or during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

Demand Resource Commercial Operation Audit is an audit initiated pursuant to Section III.13.6.1.5.4.4.

Demand Resource Forecast Peak Hours are those hours, or portions thereof, in which, absent the dispatch of Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast.

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Operable Capacity Analysis means an analysis performed by the ISO estimating the expected dispatch hours of active Demand Resources given different assumed levels of Demand Resources clearing in the primary Forward Capacity Auction.

Demand Resource Performance Incentives means the additional monthly capacity payment that a Demand Resource may earn for producing a positive Monthly Capacity Variance in a period where other Demand Resources yield a negative monthly capacity variance.

Demand Resource Performance Penalties means the reduction in the monthly capacity payment to a Demand Resource for producing a negative Monthly Capacity Variance.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and the pumping load associated with pumped storage generators) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2. The demand reduction of a Demand Response Asset is the difference between the Demand Response Asset's actual demand measured at the Retail Delivery Point, which could reflect Net Supply, at the time the Demand Response Resource to which the asset is associated is dispatched by the ISO, and its adjusted Demand Response Baseline.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8A or Section III.8B.

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

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will

be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Regulation Resource is a Real-Time Demand Response Resource eligible to provide Regulation.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2018.

Demand Response Resource Notification Time is the minimum time, from the receipt of a Dispatch Instruction, that it takes a Demand Response Resource that was not previously reducing demand to start reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the time required from the time a Demand Response Resource that was not previously reducing demand starts reducing demand in response to a Dispatch Instruction and the time the resource achieves its Minimum Reduction.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for generation and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) is the Dispatch Rate expressed in megawatts.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Resources, change External Transactions, or change the status of a Dispatchable Asset Related Demand in

accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output, consumption or demand reduction level of each generating Resource, Dispatchable Asset Related Demand and Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.13.1.4.6.1.

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions and must meet the technical requirements specified in the ISO New England Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources, however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation resources directly connected to end-use customer load and located behind the end-use customer's meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time

Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a wind resource must not exceed.

DR Auditing Period is the summer DR Auditing Period or winter DR Auditing Period as defined in Section III.13.6.1.5.4.3.1.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output level to which a Resource would have been dispatched, based on the Resource's Supply Offer and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a resource that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the resource's Supply Offer. This represents the highest MW output a Market Participant has offered for a resource for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit for all hours in which a resource has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for Resources with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for Resources without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Resource and with meeting all environmental regulations and licensing limits, and (c) for Resources undergoing Facility and Equipment Testing or auditing, the level to which the Resource requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for non-dispatchable Resources the output level at which a Market Participant anticipates its non-dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the set of Supply Offer values that are used for NCPC calculation purposes as specified in Section III.F.1.a.

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electronic Dispatch Capability is the ability to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of generating units and Dispatchable Asset Related Demands and the ability to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Resources.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum generation amount, in MWs, that a generating unit can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange as determined by the ISO settlement process for the Energy Market.

Energy Offer Cap is \$1,000/MWh.

Energy Offer Floor is negative \$150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours and Energy Non-Zero Spot Market Settlement Hours.

Enrolling Participant is the Market Participant that registers Customers for the Load Response Program.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORd) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, the Capacity Requirement from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Estimated Net Regional Clearing Price (ENRCP) is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted by certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, and, subject to ISO evaluation, for the Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

Existing Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.1 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; (v) is capable of receiving and acknowledging a Dispatch Instruction electronically; and (vi) has satisfied its Minimum Time Between Reductions.

Fast Start Generator means a generating unit that the ISO may dispatch within the hour through electronic dispatch and that meets the following criteria: (i) minimum run time does not exceed one hour; (ii) minimum down time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Payment is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider,

or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Forecast Hourly Demand Reduction means the estimated maximum quantity of energy reduction (MWh), measured at the end-use customer meter that can be produced by a Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource, in each hour of an Operating Day. For a Real-Time Emergency Generation Asset that is metered at the generator and associated with a Real-Time Emergency Generation Resource, the Forecast Hourly Demand Reduction means the estimated maximum generator output (MWh) in each hour of an Operating Day.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual descending clock auction in the Forward Capacity Market, as described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is \$14,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a “Non-Market Participant FTR Customers” and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC’s Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a generator that has been registered in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.2.7.1.1.1(a) of Market Rule 1.

Hourly Real-Time Demand Response Resource Deviation means the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.7.3.1.

Hourly Real-Time Emergency Generation Resource Deviation is calculated pursuant to Section III.13.7.1.5.8.3.1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadequate Supply is defined in Section III.13.2.8.1 of Market Rule 1.

Inadvertent Energy Revenue is defined in Section III.3.2.1(k) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(l) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled generation at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Insufficient Competition is defined in Section III.13.2.8.2 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the “Large Generator Interconnection Agreement”, the “Small Generator Interconnection Agreement”, or the “Elective Transmission Upgrade Interconnection Agreement” pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the “Large Generator Interconnection Procedures”, the “Small Generator Interconnection Procedures”, or the “Elective Transmission Upgrade Interconnection Procedures” pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Intermittent Power Resource is defined in Section III.13.1.2.2.2 of Market Rule 1.

Intermittent Settlement Only Resource is a Settlement Only Resource that is also an Intermittent Power Resource.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating

Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means generating resources that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, or Real-Time Demand Response Event Hours to other hours and reduce the amount of capacity needed, while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, chilled water storage, and other forms of electricity storage.

Load Response Program means the program implemented and administered by the ISO to promote demand side response as described in Appendix E to Market Rule 1.

Load Response Program Asset means one or more individual end-use metered customers that report load reduction and consumption, or generator output as a single set of values, are assigned an identification number, that participate in the Load Response Program and which encompass assets registered in the Real-Time Price Response Program or Real-Time Demand Response Assets, and are further described in Appendix E of Market Rule 1.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA.

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade or a Public Policy Transmission Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone or Hub. For Capacity Commitment Periods commencing on or after June 1, 2018, the Location also is a Dispatch Zone.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods commencing on or after June 1, 2018, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart CIP Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Major Transmission Outage is a major transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b)(v) of Market Rule 1.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1, to meet the Installed Capacity Requirement.

Maximum Consumption Limit is the maximum amount, in MW, available from the Dispatchable Asset Related Demand for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data except that a Self-Scheduled Dispatchable Asset Related Demand may modify its Minimum Consumption Limit on an hourly basis, as part of its Demand Bid, in order to indicate the desired level of Self-Scheduled MW.

Maximum Facility Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand of a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset, where the demand evaluated is established by adding actual metered

demand and the output of all generators located behind the asset's end-use customer meter in the same time intervals.

Maximum Generation is the maximum generation output of a Real-Time Demand Response Asset comprised of Distributed Generation or the maximum generation output of a Demand Response Asset comprised of Distributed Generation.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset's peak load less its uninterruptible load. For assets that deliver reductions through the use of generation, the Maximum Interruptible Capacity is the difference between the generator's maximum possible output and its expected output when not providing demand reduction. For assets that deliver demand reduction and Net Supply, the Maximum Interruptible Capacity is the asset's peak load plus Maximum Net Supply as measured at the Retail Delivery Point.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, of a Demand Response Asset, Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

Maximum Net Supply is an estimate of the maximum hourly Net Supply for a Demand Response Asset as measured from the Demand Response Asset's Retail Delivery Point.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time a 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 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 Value of the Demand Resource is greater than or equal to the

amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the Demand Reduction Value for an Existing Demand Resource is not overstated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1, which includes Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by a Demand Resource supplier as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by Demand Resource suppliers during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MG TSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MG TSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Minimum Consumption Limit is the minimum amount, in MW, available from a Dispatchable Asset Related Demand that is not available for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data.

Minimum Down Time is the number of hours that must elapse after a Generator Asset has been released for shutdown at or below its Economic Minimum Limit before the Generator Asset can be brought online and be released for dispatch at its Economic Minimum Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources to operate at or below Economic Minimum Limit, in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit.

Minimum Time Between Reductions is the minimum number of hours that a Market Participant requires between the time the Demand Response Resource receives a Dispatch Instruction from the ISO to not reduce demand and the time the Demand Response Resource receives a Dispatch Instruction from the ISO to reduce demand.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Variance means a Demand Resource's actual monthly Capacity Value established pursuant to Section III.13.7.1.5.1 of Market Rule 1, minus the Demand Resource's final Capacity Supply Obligation for the month.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

Net Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

Net Supply is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.

Net Supply Limit is the estimated portion of the offered Maximum Reduction of a Demand Response Resource that would be provided through Net Supply. The Net Supply Limit is calculated by multiplying the offered Maximum Reduction of the Demand Response Resource by the ratio of total Net Supply to total demand reduction performance from the prior like Seasonal DR Audit of the Demand Response Assets that are mapped to the Demand Response Resource for the month.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date

until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Required is the amount of additional capacity required to meet the Installed Capacity Requirement or a Capacity Zone's Local Sourcing Requirement, as described in Section III.13.2.8.1.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.2 of Market Rule 1.

New Demand Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III 13.1.4.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Resource.

New Demand Resource Show of Interest Form is described in Section III.13.1.4.2 of Market Rule 1.

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but does not have a winter audit value and a summer audit value.

New Demand Response Asset Audit is an audit of a New Demand Response Asset performed pursuant to Section III.13.6.1.5.4.8.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Nodal Amount is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a generating unit that must be paid to Market Participants with an Ownership Share in the unit for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the generating unit is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.3.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an increment of an Existing Capacity Resource that is treated as a New Capacity Resource in the Forward Capacity Auction and that has not been declared commercial and has not had its capacity rating verified by the ISO.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. “Non-Incumbent Transmission Developer” also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to

the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Intermittent Settlement Only Resource is a Settlement Only Resource that is not an Intermittent Power Resource.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-Price Retirement Request is a binding request to retire the entire capacity of a Generating Capacity Resource as described in Section III.13.1.2.3.1.5.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2018, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2018, Demand Response Resources for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is, for a generating Resource, a Supply Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR available from the Resource from an off-line state, and, for a Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched, is a Demand Bid or Demand Reduction Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR or TMSR available from the Resource.

Offered CLAIM30 is a Supply Offer, Demand Bid or Demand Reduction Offer value between 0 and the CLAIM30 of a Resource that represents the amount of TMOR available from an off-line generating Resource, or Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched.

Offered Full Reduction Time is the value calculated pursuant to Section III.13.6.1.5.4.6.

On-Peak Demand Resource is a type of Demand Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a generating unit asset or Load Asset, where such unit or load is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The “Phase I Transfer Capability” is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Resource participate in the Forward Capacity Market, as described in Section III.13.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b)(iii) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(c)(iii) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E1.8 for Capacity Commitment Periods commencing prior to June 1, 2018, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2018.

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Real-Time Demand Response Resources of such hours.

Real-Time Demand Response Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Demand Response Resource.

Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing

electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

Real-Time Emergency Generation Resource is Distributed Generation whose federal, state and/or local air quality permits, rules or regulations limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(ii) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(c)(ii) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b)(i) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(c)(i) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b)(iv) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(c)(iv) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Price Response Program is the program described in Appendix E to Market Rule 1.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements

under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, for Capacity Commitment Periods commencing on or after June 1, 2018, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in \$/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2018, a Demand Response Resource. For purposes of providing Regulation, Resource means a generating unit, a Dispatchable Asset Related Demand, a Demand Response Regulation Resource or an Alternative Technology Regulation Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission’s corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

Seasonal Peak Demand Resource is a type of Demand Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Self-Schedule is the action of a Market Participant in committing or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing or scheduling a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been scheduled or dispatched by the ISO to provide the Energy. For a Dispatchable Asset Related Demand, Self-Schedule is the action of a Market Participant in committing or scheduling a Dispatchable Asset Related Demand to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the Dispatchable Asset Related Demand would have been scheduled or dispatched by the ISO to consume Energy. Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to: (i) a Generator Asset's Economic Minimum Limit; (ii) a Dispatchable Asset Related Demand's Minimum Consumption Limit.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated

with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to remove

itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service

or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock; (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of (1) a generating Resource that can be converted fully into energy within ten minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of (1) a generating Resource that is electrically synchronized to the New England Transmission System that can be converted fully into energy within ten minutes from the request of the ISO; (2) a Dispatchable Asset Related Demand pump that is electrically synchronized to the New England Transmission System that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO for which none of the associated Demand Response Assets have a generator whose output can be controlled located behind the Retail Delivery Point other than emergency generators that cannot operate electrically synchronized to the New England Transmission System.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) means the reserve capability of (1) a generating Resource that can be converted fully into energy within thirty minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within thirty minutes from the request of the ISO.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a

single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart O&M Payment is the annual compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than \$0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1

III.8 Demand Response Baselines

III.8A Demand Response Baselines Before June 1, 2018

Section III.8.A shall govern Demand Response Baselines calculated for Capacity Commitment Periods commencing prior to June 1, 2018.

A Demand Response Baseline is calculated for any Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that requires a baseline on a daily basis using five-minute meter data.

8A.1 Establishing the Initial Demand Response Baseline

The Demand Response Baseline for a new Real-Time Demand Response Asset or Real-Time Emergency Generation Asset (an asset with no previously computed Demand Response Baseline) shall be the simple average of meter data for the asset for the same five-minute interval from the first 10 consecutive weekdays (excluding Demand Response Holidays) with a complete set of interval meter data. A Market Participant may not submit Demand Reduction Offers until the month following the initial establishment of a Demand Response Baseline for an asset.

If two or more existing Real-Time Demand Response Assets (assets registered with the ISO with previously computed Demand Response Baselines) located at or behind the same retail delivery point are consolidated into one Real-Time Demand Response Asset located at the retail delivery point, or a significant change in load, generation, or reported meter data at an existing Real-Time Demand Response Asset or Real-Time Emergency Generation Asset occurs, a new initial Demand Response Baseline must be established for the asset.

8A.2 Establishing the Demand Response Baseline

Prior to June 1, 2017, if, for a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

- (a) the asset has been dispatched or audited in the present day pursuant to Section III.13, or;
- (b) the Demand Reduction Offer associated with the asset is eligible in the present Operating Day for payments pursuant to Section III.E1.9, or;
- (c) the present day is a Demand Response Holiday, Saturday or Sunday, then:

the asset's Demand Response Baseline, in each five-minute interval, for the next day is equal to the Demand Response Baseline, in the same five-minute interval from the present day.

Beginning June 1, 2017, for a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline, the asset's Demand Response Baseline in each five-minute interval of each day shall be the simple average of meter data for the same five-minute interval from 10 weekdays (excluding Demand Response Holidays), chosen from the previous 30 weekdays (excluding Demand Response Holidays) pursuant to Section III.8A.3.

8A.3 Determining the Meter Data Used in the Demand Response Baseline

Prior to June 1, 2017, if, for a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

- (i) the present day is not a Demand Response Holiday, Saturday or Sunday; the asset has not been dispatched or audited in the present day pursuant to Section III.13; and the Demand Reduction Offer associated with the asset is not eligible in any hour of the present day for payments pursuant to Section III.E1.9; or
- (ii) the present day is not a Demand Response Holiday, Saturday or Sunday and more than seven of the prior 10 weekdays (excluding Demand Response Holidays) have established a Demand Response Baseline determined pursuant to Section III.8A.2; then:

the asset's Demand Response Baseline, in each five-minute interval, for the next day is calculated as the sum of 0.9 times the asset's Demand Response Baseline established for the present day in the same five-minute interval and 0.1 times the asset's meter data in the same five-minute interval from the present day.

Beginning June 1, 2017, for each Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline, the asset's Demand Response Baseline in each five-minute interval of each day shall be the simple average of meter data for the same five-minute interval from 10 weekdays (excluding Demand Response Holidays), chosen from the previous 30 weekdays (excluding Demand Response Holidays) as follows.

- (a) Where there are at least 10 days that meet the following criteria:
 - (i) the asset has not been dispatched or audited pursuant to Section III.13; and

- (ii) the Demand Reduction Offer associated with the asset was not eligible in the Operating Day for payments pursuant to Section III.E1.9; and
 - (iii) if the asset is on a forced or scheduled curtailment, actual meter data values have not been submitted for any interval of the day pursuant to Section III.8A.5.3;
- then meter data from the 10 most recent such days will be used in the Demand Response Baseline calculation.
- (b) Where there are less than 10 days that meet the criteria in (a), meter data from all days that meet the criteria in (a) will be used; in addition, until 10 days are identified, meter data will be used from the most recent days that do not meet one or more of the criteria in (a).

8A.4 Baseline Adjustment

8A.4.1 Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets Without Generation or From Real-Time Emergency Generation Assets Without Additional Generation

For each day the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between the asset's actual metered demand and its Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load.

8A.4.2 Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets with Generation or From Real-Time Emergency Generation Assets With Additional Generation

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between the sum of the asset's actual metered demand and the output of all generators, or for Real-Time Emergency Generation Assets all additional generators, located

behind the asset's end-use customer meter in the same time intervals and the asset's Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Facility Load.

8A.4.3 Baseline Adjustment for Real-Time Demand Reductions Produced By Directly Metered Generation

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset that is comprised of a Distributed Generation asset located behind the end-use customer meter of an individual end-use customer facility, the asset's Demand Response Baseline shall not be subject to the baseline adjustment.

8A.4.4 Baseline Adjustment for Real-Time Demand Reductions Produced by a Real-Time Demand Response Asset Located At a Retail Delivery Point Where There Are No Other Real-Time Demand Response Assets At or Behind that Retail Delivery Point

For a Real-Time Demand Response Asset located at a retail delivery point with no other Real-Time Demand Response Assets at or behind the same retail delivery point, the metered output of any Real-Time Emergency Generation Assets in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline. Each generator located behind an individual end-use customer's retail delivery point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between (1) the sum of the asset's actual metered demand as measured at the asset's retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the asset's retail delivery point in the same time intervals, and (2) the asset's Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day,

which may increase or decrease the Demand Response Baseline. However, for assets that cannot produce net supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Facility Load. For assets that can produce net supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than the maximum amount (MW) that the asset is allowed to push back into the electric system per the applicable generator interconnection agreement (where the amount (MW) pushed back into the electric system is a negative value) and shall not exceed the asset's Maximum Facility Load.

The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval minus the sum of the metered demand measured at the retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of any Real-Time Emergency Generation Assets is greater than its adjusted Demand Response Baseline.

8A.5 Establishing the Demand Response Baseline for a Day with a Scheduled or a Forced Curtailment

8A.5.1 Notification of Forced and Scheduled Curtailments

A Market Participant, with a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset for which a Demand Response Baseline measured at the retail delivery point is utilized, may notify the ISO of a forced curtailment for any reductions in demand that occur as a result of actions outside the control of the Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that is subject to the forced curtailment.

A Market Participant may notify the ISO of a scheduled curtailment at least seven calendar days before the start of any reductions in a Real-Time Demand Response Asset's demand or a Real-Time Emergency Generation Asset's demand where a Demand Response Baseline measured at the retail delivery point is utilized, that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Real-Time Demand Response Assets or Real-Time Emergency Generation Assets with a Maximum Interruptible Capacity of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start

of the curtailment. The length of a scheduled curtailment must be a minimum of a single calendar day and may not exceed a total of 14 calendar days per Capacity Commitment Period.

8A.5.2 Submitting Meter Data Values for Days with Forced or Scheduled Curtailments

For each calendar day on which a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset where a Demand Response Baseline measured at the retail delivery point is utilized, is on a forced or scheduled curtailment, the asset's Demand Designated Entity shall submit to the ISO meter data values equal to the unadjusted baseline calculated for the first day of the forced or scheduled curtailment for all intervals excluding those in which the Real-Time Demand Response Resource with which the Real-Time Demand Response Asset is associated, or the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13, and excluding those in which a Demand Reduction Offer associated with the Real-Time Demand Response Asset had cleared day-ahead or became eligible in real-time pursuant to Section III.E1 on a day with an unanticipated forced curtailment.

8A.5.3 Performance Assessment for Days with Forced or Scheduled Curtailments

To assess the performance of Real-Time Demand Response Assets and Real-Time Emergency Generation Assets that are on a forced or scheduled curtailment, actual meter data values shall be submitted to the ISO for intervals during which the Real-Time Demand Response Resource with which the Real-Time Demand Response Asset is associated, or the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13, and intervals in which a Demand Reduction Offer associated with the Real-Time Demand Response Asset was cleared day-ahead or became eligible during the Operating Day pursuant to Section III.E1 on a day with an unanticipated forced curtailment.

III.8B Demand Response Baselines Beginning June 1, 2018

Section III.8B shall govern Demand Response Baselines calculated for Capacity Commitment Periods commencing on or after June 1, 2018.

A Demand Response Baseline is calculated in five-minute intervals for each Demand Response Asset and each Real-Time Emergency Generation Asset that is metered at the Retail Delivery Point for the following three day types:

- (a) weekdays (excluding Demand Response Holidays);
- (b) Saturdays; and
- (c) Sundays and Demand Response Holidays.

8B.1 Demand Response Baseline Calculations

If a Demand Response Asset's metered demand represents Net Supply in an interval, that Net Supply will be used in the Demand Response Baseline calculations for that interval pursuant to Sections III.8B.2, III.8B.3, and III.8B.4.

8B.1.1 Demand Response Baseline Real-Time Emergency Generation Asset Adjustment

To the extent a Real-Time Emergency Generation Asset is located at the same Retail Delivery Point as a Demand Response Asset, the metered output of the Real-Time Emergency Generation Asset, in each five-minute interval, shall be added to the metered demand measured at the Retail Delivery Point in the same intervals for purposes of determining the Demand Response Asset's Demand Response Baseline.

8B.2 Establishing an Initial Demand Response Baseline and Resetting a Baseline

An initial Demand Response Baseline will be established for a Demand Response Asset with no previously computed Demand Response Baseline, and for a Real-Time Emergency Generation Asset with no previously computed Demand Response Baseline when a Demand Response Baseline measured at the Retail Delivery Point is utilized for the asset. A Demand Response Baseline will be reset using the initial baseline calculation methodology set forth below when a significant change in load, generation, or reported meter data at an existing Demand Response Asset or Real-Time Emergency Generation Asset occurs.

For a weekday (excluding Demand Response Holidays) day type, the initial Demand Response Baseline, or reset of a Demand Response Baseline, for each five-minute interval shall be the simple average of meter data for the asset for the same five-minute interval, subject to the conditions in Section III.8B.1, from the first 10 consecutive weekdays (excluding Demand Response Holidays) with a complete set of interval meter data.

For a Saturday day type, the initial Demand Response Baseline, or a reset of a Demand Response Baseline, for each five-minute interval shall be the simple average of meter data for the asset for the same five-minute interval, subject to the conditions in Section III.8B.1, from the first five consecutive Saturdays with a complete set of interval meter data.

For a Sunday and Demand Response Holiday day type, the initial Demand Response Baseline, or a reset of a Demand Response Baseline, for each five-minute interval shall be the simple average of meter data for the asset for the same five-minute interval, subject to the conditions in Section III.8B.1, from the first five consecutive Sundays and Demand Response Holidays with a complete set of interval meter data.

A Market Participant may not submit Demand Reduction Offers for a Demand Response Resource for a given day type in a given month unless the initial baseline for that day type for at least one Demand Response Asset mapped to the Demand Response Resource was established at least seven calendar days prior to the first day of that month. This condition applies when establishing an initial Demand Response Baseline but not when resetting a Demand Response Baseline.

8B.3 Determining the Meter Data Used to Calculate the Demand Response Baseline for a Weekday (excluding Demand Response Holidays) Day Type

For a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for weekdays (excluding Demand Response Holidays), the asset's weekday (excluding Demand Response Holiday) Demand Response Baseline in each five-minute interval shall be the simple average of meter data for the same five-minute interval from 10 weekdays (excluding Demand Response Holidays), chosen from the previous 30 weekdays (excluding Demand Response Holidays) as follows.

- (a) If at least 10 of the previous 30 weekdays (excluding Demand Response Holidays) meet the following criteria, then the 10 most recent such days will be used: (i) the resource associated with the asset has not received a Dispatch Instruction for an amount greater than 0 MW; and (ii) if the

asset is on a forced or scheduled curtailment, actual meter data values have not been submitted for any interval of the day pursuant to Section III.8B.6.3.

- (b) If less than 10 of the previous 30 weekdays (excluding Demand Response Holidays) meet the criteria in (a), then, in addition to those days that meet the criteria in (a), the most recent weekday (excluding Demand Response Holidays) that does not meet one or more of the criteria in (a) will be used, until 10 days are identified.

8B.4 Determining the Meter Data Used to Calculate the Demand Response Baseline for a Saturday Day Type or a Sunday and Demand Response Holiday Day Type

8B.4.1 Determining the Meter Data Used to Calculate the Demand Response Baseline for a Saturday Day Type

For a Saturday day type: For a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for Saturdays, the asset's Demand Response Baseline in each five-minute interval shall be the simple average of meter data for the same five-minute interval from five Saturdays, chosen from the previous 42 calendar days as follows.

- (a) If at least five Saturdays meet the following criteria, then the five most recent such days will be used: (i) the resource associated with the asset did not receive a Dispatch Instruction for an amount greater than 0 MW; and (ii) if the asset is on a forced or scheduled curtailment, actual meter data values were not submitted for any interval of the day pursuant to Section III.8B.6.3.
- (b) If less than five Saturdays meet the criteria in (a), then, in addition to those days that meet the criteria in (a), the most recent Saturday that does not meet one or more of the criteria in (a) will be used, until five days are identified.

8B.4.2 Determining the Meter Data Used to Calculate the Demand Response Baseline for a Sunday and Demand Response Holiday Day Type

For a Sunday and Demand Response Holiday day type: For a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for Sundays and Demand Response Holidays, the asset's Sunday and Demand Response Holiday Demand Response Baseline in each five-minute interval shall be the simple average of meter data for the same five-minute

interval from five Sundays and Demand Response Holidays, chosen from the previous 42 calendar days as follows.

- (a) If at least five Sundays and Demand Response Holidays meet the following criteria, then the five most recent such days will be used: (i) the resource associated with the asset did not receive a Dispatch Instruction for an amount greater than 0 MW; and (ii) if the asset is on a forced or scheduled curtailment, actual meter data values were not submitted for any interval of the day pursuant to Section III.8B.6.3.
- (b) If less than five Sundays and Demand Response Holidays meet the criteria in (a), then, in addition to those days that meet the criteria in (a), the most recent Sunday or Demand Response Holiday that does not meet one or more of the criteria in (a) will be used, until five days are identified.

8B.5 Baseline Adjustment

The Demand Response Baseline for each Demand Response Asset and each Real-Time Emergency Generation Asset is updated approximately every quarter hour by an adjustment factor that is calculated in accordance with this Section III.8B.5, which may increase or decrease the baseline.

- (a) An adjustment factor is calculated if the resource with which the asset is associated is not in a period of dispatch (as defined by the resource's Dispatch Instruction including the Demand Response Resource Start-Up Time and Demand Response Resource Notification Time). The adjustment factor is calculated with real-time telemetry data in Real-Time and is calculated with revenue quality metering data for settlement purposes.
- (b) For an asset that is part of a resource that is not in a period of dispatch, the adjustment factor is calculated using five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the start of the quarter hour. For an asset that is part of a resource that has received a Dispatch Instruction, the adjustment factor is calculated using five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the start of the quarter hour before the Dispatch Instruction was issued. After completion of a dispatch, the adjustment factor for an asset will be calculated using the five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the start of the quarter hour before the Dispatch Instruction was issued, until sufficient time has elapsed to calculate the adjustment using post-dispatch interval data.
- (c) For a Demand Response Asset, the adjustment factor is equal to the average difference (MW) between the Demand Response Asset's telemetered or metered demand, which shall be adjusted

pursuant to Section III.8B.1.1 (inclusive of any Net Supply), and its Demand Response Baseline during the three intervals. For a Real-Time Emergency Generation Asset the adjustment factor is equal to the average difference (MW) between the Real-Time Emergency Generation Asset's telemetered or metered demand and its Demand Response Baseline during the three intervals.

- (d) For Demand Response Assets that cannot produce Net Supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load. For Demand Response Assets that can produce Net Supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than the maximum amount (MW) that the asset is allowed to push back into the electric system per the applicable generator interconnection agreement (where the amount (MW) pushed back into the electric system is a negative value) and shall not exceed the asset's Maximum Facility Load.

8B.6 Establishing the Demand Response Baseline for a Day with a Scheduled or a Forced Curtailment

8B.6.1 Notification of Forced and Scheduled Curtailments

A Market Participant, with a Demand Response Asset or a Real-Time Emergency Generation Asset for which a Demand Response Baseline measured at the Retail Delivery Point is utilized, may notify the ISO of a forced curtailment for any reductions in demand that occur as a result of actions outside the control of the Demand Response Asset or Real-Time Emergency Generation Asset that is subject to the forced curtailment.

A Market Participant may notify the ISO of a scheduled curtailment at least seven calendar days before the start of any reductions in a Demand Response Asset's demand or a Real-Time Emergency Generation Asset's demand where a Demand Response Baseline measured at the Retail Delivery Point is utilized, that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Demand Response Assets or Real-Time Emergency Generation Assets with a Maximum Interruptible Capacity of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The length of a scheduled curtailment must be a minimum of a single calendar day and may not exceed a total of 14 calendar days per Capacity Commitment Period.

III.8B.6.2 Submitting Meter Data Values for Days with Forced or Scheduled Curtailments

For each calendar day on which a Demand Response Asset or a Real-Time Emergency Generation Asset, where a Demand Response Baseline measured at the Retail Delivery Point is utilized, is on a forced or scheduled curtailment pursuant to Section III.8B.6.1, the asset's Demand Designated Entity shall submit to the ISO meter data values equal to the unadjusted baseline for the day type, calculated on the first occurrence of that day type during the forced or scheduled curtailment, for all intervals excluding those intervals in which:

- (a) a Capacity Scarcity Condition existed in the Capacity Zone in which the Demand Response Asset is located,
- (b) the Demand Response Resource with which the Demand Response Asset is associated was dispatched in Real-Time pursuant to Section III.E2 on the first day of an unanticipated forced curtailment, or
- (c) the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13.

III.8B.6.3 Performance Assessment for Days with Forced or Scheduled Curtailments

To assess the performance of Demand Response Assets and Real-Time Emergency Generation Assets that are on a forced or scheduled curtailment, actual meter data values shall be submitted to the ISO for intervals during which:

- (a) a Capacity Scarcity Condition existed in the Capacity Zone in which the Demand Response Asset is located,
- (b) the Demand Response Resource with which the Demand Response Asset is associated was dispatched in Real-Time pursuant to Section III.E2 on the first day of an unanticipated forced curtailment, or
- (c) the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13.

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (Section III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section III.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Resource, New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the FCM Deposit.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1.

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than \$200 per kilowatt of the whole resource's summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than \$100 per kilowatt of the whole resource's summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The \$100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.

The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output greater than 2 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, but less than or equal to the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than \$200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff

(or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section does not cause the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement, the Project Sponsor must submit a New Capacity Qualification Package but is not required to submit a New Capacity Show of Interest Form for the incremental amount by the New Capacity Qualification Deadline. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.3 causes the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement or MW amount approved pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), the Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than \$200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.1.5. Treatment of Resources that are Partially New and Partially Existing.

For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.1.3 or Section III.13.1.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline. A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

III.13.1.1.1.7 Renewable Technology Resources.

To participate in the Forward Capacity Market as a Renewable Technology Resource, a Generating Capacity Resource or an On-Peak Demand Resource (including every asset that is part of the On-Peak Demand Resource) must satisfy the following requirements:

- (a) receive an out-of-market revenue source supported by a state- or federally-regulated rate, charge or other regulated cost recovery mechanism;
- (b) qualify as a renewable or alternative energy generating resource under any New England state's mandated (either by statute or regulation) renewable or alternative energy portfolio standards as

in effect on January 1, 2014, or, in states without a standard, qualify under that state's renewable energy goals as a renewable resource (either by statute or regulation) as in effect on January 1, 2014. The resource must qualify as a renewable or alternative energy generating resource in the state in which it is geographically located;

(c) participate in a Forward Capacity Auction for a Capacity Commitment Period beginning on or after June 1, 2018 as a New Generating Capacity Resource or New Demand Resource pursuant to Section III.13.1.1, and;

(d) has been designated for treatment as a Renewable Technology Resource pursuant to Section III.13.1.1.2.9.

An Export De-List Bid or Administrative Export De-List Bid may not be submitted for Generating Capacity Resources that assumed a Capacity Supply Obligation by participating in a Forward Capacity Auction as a Renewable Technology Resource.

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.

For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also submit to the ISO, or in the case of an Import Capacity Resource seeking to qualify with an Elective Transmission Upgrade be associated with, an Interconnection Request under Schedules 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the interconnection procedures described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the FCM Deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be

irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, Material Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23, or Section 4.4 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein or the New Capacity Show of Interest Form shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor's contact information; the Project Sponsor's ISO customer status; the project's expected Commercial Operation date; the project address or location, and if relevant, asset identification number; the status of the project under the interconnection procedures described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project's equipment configuration, including a

description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff. In the case of a resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource that is supported by an Internal Elective Transmission Upgrade, all Queue Positions associated with the project must be submitted in the New Capacity Show of Interest Form. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period pursuant to Section III.13.1.1.2.2.1.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must achieve, prior to the close of the New Capacity Show of Interest Submission Window, control of the project site for the duration of the relevant Capacity Commitment Period, which shall be as defined in Section 4.1 of Schedule 22, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits.** In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing.** In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders.** In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2.2(d) and that accounts for more than five percent of the total project cost. For an Import Capacity Resource associated with an Elective Transmission Upgrade that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, major components shall also include, to the extent applicable, transmission facilities and associated substation equipment.

(d) **Substantial Site Construction.** In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery.** In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing.** In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (d) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent Commercial Operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning.** In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation.** In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. Offer Information.

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity at or above the Economic Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity Resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.1.2.2.4. Capacity Commitment Period Election.

In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional

and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity.

In addition to the information described elsewhere in this Section III.13.1.1.2.2:

- (a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.
- (b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.
- (c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource and Intermittent Settlement Only Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

- (a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);
- (b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource or the Intermittent Settlement Only Resource.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a Material Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23 and Section 4.4 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service in a manner that meets the Capacity

Capability Interconnection Standard in accordance with the provisions in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource's Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) or Elective Transmission Upgrade Interconnection Customer as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s) or Elective Transmission Upgrade Interconnection Customer, as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the

Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

(g) New Generating Capacity Resources, or portions thereof, shall not be considered to have met their Capacity Supply Obligation for the purposes of this Forward Capacity Market and shall not receive compensation if any upgrades to be completed by the Project Sponsor required to remove overlapping interconnection impacts as identified in (f) have not been completed, including, any upgrades identified in a restudy pursuant to Section 3.2.1.3 of Schedule 22, Section 1.7.1.3 of Schedule 23, or Section 3.2.1.3 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff in time for the Capacity Commitment Period unless the Capacity Supply Obligation is appropriately covered.

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource's New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

- (a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;
- (b) whether the critical path schedule includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule are reasonable and likely to be met;
- (d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and
- (e) whether, in the case of an Intermittent Power Resource or Intermittent Settlement Only Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified

Capacity for such a resource shall be equal to the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. [Reserved.]

III.13.1.1.2.7. Opportunity to Consult with Project Sponsor.

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

- (a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;
- (b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource's New Capacity Qualification Package was not accepted;
- (c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);
- (d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource's summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;
- (e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Resource; (ii) for the notification to a Conditional Qualified New Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Resource, the Queue Position of the Conditional Qualified New Resource; and
- (f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal

Market Monitor's determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.1.2.9 Renewable Technology Resource Election.

A Project Sponsor or Market Participant electing Renewable Technology Resource treatment for the FCA Qualified Capacity of a New Generating Capacity Resource or New Demand Resource shall submit a Renewable Technology Resource election form no later than five Business Days after the date on which the ISO provides qualification determination notifications pursuant to Section III.13.1.1.2.8 or Section III.13.1.4.2.5.3. Only the portion of the FCA Qualified Capacity of the resource that meets the requirements of Section III.13.1.1.1.7 is eligible for treatment as a Renewable Technology Resource.

Renewable Technology Resource elections may not be modified or withdrawn after the deadline for submission of the Renewable Technology Resource election form.

The submission of a Renewable Technology Resource election that satisfies the requirements of Section III.13.1.1.1.7 will invalidate a prior multi-year Capacity Supply Obligation and Capacity Clearing Price election for the same resource made pursuant to Section III.13.1.4.2.2.5 or Section III.13.1.1.2.2.4 for a Forward Capacity Auction.

III.13.1.1.2.10 Determination of Renewable Technology Resource Qualified Capacity.

- (a) If the total FCA Qualified Capacity of Renewable Technology Resources exceeds the cap specified in subsections (b), (c) and (d) the qualified capacity value of each resource shall be prorated by the ratio of the cap divided by the total FCA Qualified Capacity. The ISO shall notify the Project Sponsor or Market Participant, as applicable, of the Qualified Capacity value of its resource no more than three Business Days after the deadline for submitting Renewable Technology Resource elections.
- (b) The cap for the Capacity Commitment Period beginning on June 1, 2018 is 200 MW.
- (c) The cap for the Capacity Commitment Period beginning on June 1, 2019 is 400 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior Capacity Commitment Period.

- (d) The cap for each Capacity Commitment Period beginning on or after June 1, 2020 is 600 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior two Capacity Commitment Periods.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Resource or Existing Demand Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each

year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that

is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006 summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be established pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e).

(b) The Intermittent Power Resource's or Intermittent Settlement Only Resource's summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.

- (a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in each of the previous winter periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.
- (b) The Intermittent Power Resource's and Intermittent Settlement Only Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2(a).
- (c) The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.
- (d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

- (a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity

Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the two treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource's summer Qualified Capacity set to the most recent

summer Seasonal Claimed Capability as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) [Reserved.]

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only

Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, except as provided for in Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.5.2. An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section

III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

The Dynamic De-List Bid Threshold for a Forward Capacity Auction is \$5.50/kW-month. The Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders.

III.13.1.2.3.1.1. Static De-List Bids.

A Lead Market Participant with an Existing Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation for that resource, or a portion thereof, at prices at or above the Dynamic De-List Bid Threshold during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs). The curve may in no case increase the quantity offered as the

price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Lead Market Participant must notify the ISO if the Existing Capacity Resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests).

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, a Lead Market Participant that submitted a Static De-List Bid may: (a) lower the price of any price-quantity pair of a Static De-List Bid, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or; (b) withdraw any price-quantity pair of a Static De-List Bid.

III.13.1.2.3.1.2. Permanent De-List Bids.

A Lead Market Participant with an Existing Capacity Resource seeking to specify a price below which it would not accept a Capacity Supply Obligation permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource's full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids at or above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource, an Intermittent Settlement Only Resource or a Renewable Technology Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids at or above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource, an Intermittent Settlement Only Resource or a Renewable Technology Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-

List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity Commitment Period. Administrative Export De-List Bids shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.

A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request submitted in accordance with the timing requirements of Section III.13.1.2.3.1.5.2 supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.

The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a Permanent De-List Bid for which an Internal Market Monitor-determined price has been established pursuant to Section III.13.1.2.3.2.1.1.1, a Non-Price Retirement Request may be submitted for the affected portion of the bid within 14 days after the issuance by the ISO of the qualification determination notification or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.

III.13.1.2.3.1.5.3. Reliability Review of Non-Price Retirement Requests.

The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request

will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

III.13.1.2.3.1.5.4. Obligation to Retire.

A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5.3(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.

III.13.1.2.3.1.6. Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. Internal Market Monitor Review.

The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

- (i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.
- (ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive de-listing of each individual asset in preferred de-list order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of bids as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The bids of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid as described in Section III.13.1.2.3.2.1.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Capacity Resources.

The Internal Market Monitor shall review bids for Existing Capacity Resources as follows.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids at or Above the Dynamic De-List Bid Threshold, and Permanent De-List Bids at or Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid, each Export Bid at or above the Dynamic De-List Bid Threshold, and each Permanent De-List Bid at or above the Dynamic De-List Bid

Threshold to determine whether the bid is consistent with: (1) the Existing Capacity Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); (3) reasonable risk premium assumptions (as determined pursuant to Section III.13.1.2.3.2.1.4); and (4) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). Sufficient documentation and information about each of these bid components must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments and risk premiums, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate. The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

III.13.1.2.3.2.1.1.1. Review of Permanent De-List Bids and Export Bids.

If the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that a Permanent De-List Bid or an Export Bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid. If an Internal Market Monitor-determined price is established for a Permanent De-List Bid or an Export Bid, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the Internal

Market Monitor-determined price based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor.

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.

If the Internal Market Monitor determines, after due consideration and consultation with a Lead Market Participant, that a Static De-List Bid is not consistent with a resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid that is consistent with its determination of the foregoing.

If an Internal Market Monitor-determined price is established for a bid, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission described in Section III.13.8.1(a) shall include an explanation of the Internal Market Monitor-determined price based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor.

III.13.1.2.3.2.1.2. Net Going Forward Costs.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid, Export Bid at or above the Dynamic De-List Bid Threshold, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net going forward costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. A Static De-List Bid, Export Bid at or above the Dynamic De-List Bid Threshold, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing Capacity Resource's net going forward costs based on a review of the data submitted in the following formula. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{[GFC - (IMR - PER)] \times InfIndex}{(CQ_{Summer, kW}) \times (12, months)}$$

Where:

GFC = annual going forward costs, in dollars. These are costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

$CQ_{Summer, kW}$ = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid), this value shall be calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and

maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be \$0.00. As soon as practicable, the resource's total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected

InfIndex = inflation index. $\text{infIndex} = (1 + i)^4$

Where: "i" is the most recent reported 4- Year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid, Export Bid at or above the Dynamic De-List Bid Threshold, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.13.1.2.3.2.1.4. Risk Premium.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid, Export Bid at or above the Dynamic De-List Bid Threshold, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide

documentation separately detailing any risk premium included in the bid. This documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.13.1.2.3.2.1.2 may be included in this risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the Forward Capacity Market is consistent with the participant's corporate risk management practices.

III.13.1.2.3.2.1.5. Opportunity Costs.

To the extent that an Existing Capacity Resource submitting a Static De-List Bid, Export Bid at or above the Dynamic De-List Bid Threshold, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, expected Capacity Performance Payments, or risk premium components of the bid, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. Administrative Export De-List Bids.

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

Age of Existing Resource (years)	Remaining Life (years)	Annual Rate of Capital Cost Recovery
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{\text{Cost Of Capital}}{(1 - (\text{I} + \text{CostOfCapital})^{-\text{RemainingLife}})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Qualification Determination Notification for Existing Capacity.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid and Export Bid concerning the result of the Internal Market Monitor's de-list bid review conducted pursuant to Section III.13.1.2.3.2. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external Demand Resource may not be an Existing Import Capacity Resource or a New Import Capacity Resource. External nodes shall be established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff.

An Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be included in the FCM (1) after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Forward Capacity Market qualification requirements or (2) after it has met the requirements of an Elective Transmission Upgrade with Long Lead Time Facility treatment pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff. An external node for such an Elective Transmission Upgrade will be modeled for participation in the Forward Capacity Market after the Import Capacity Resource meets the requirements to participate in the FCA. The Qualified Capacity of an Import Capacity Resource associated with an Elective Transmission Upgrade shall not exceed the Capacity Network Import Interconnection Service Interconnection Request. In order for an Elective Transmission Upgrade to maintain its Capacity Network Import Interconnection Service, an associated Import Capacity Resource must meet the Forward Capacity Market qualification requirements and offer into each Forward Capacity Auction. Otherwise, the Capacity Network Import Interconnection Service will revert to Network Import Interconnection Service for the portion of the Capacity Network Import Interconnection Service for which no Import Capacity Resource is offered into the Forward Capacity Auction and the Elective Transmission Upgrade's Interconnection Agreement will be revised. The provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election, shall apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade seeking to reestablish Capacity Network Import Interconnection Service if the threshold to be treated as a new resource in Section III.13.1.1.1.4 is met. If the threshold to be treated as a new increment in Section III.13.1.1.1.3 is met, only the increment will be eligible for the provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election.

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. Qualified Capacity for Existing Import Capacity Resources.

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3.A Qualification Process for Existing Import Capacity Resources that are not associated with an Elective Transmission Upgrade with Capacity Network Import Interconnection Service.

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

- (a) The Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.
- (b) The rationing election described in Section III.13.1.2.3.1 shall not apply.
- (c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3 for the duration of the contracts as listed.

For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3, no later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3.

Contract Description	MW	Contract End Date
NYPA: NY – NE: CMEEC	13.2	8/31/2025
NYPA: NY – NE: MMWEC	53.3	8/31/2025
NYPA: NY – NE: Pascoag	2.3	8/31/2025
NYPA: NY– NE: VELCO	15.3	8/31/2025
	84.1	
VJO: Highgate – NE	Up to 225	10/31/2016
VJO: Highgate – NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II – NE	Up to 110	10/31/2016

(d) In addition to the review described in Section III.13.1.2.3.2, the Internal Market Monitor shall review each bid from Existing Import Capacity Resources. A bid from an Existing Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.3.B. Qualification Process for Existing Import Capacity Resources that are associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service. Existing Import Capacity Resources associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be subject to the same qualification process as Existing Generating Capacity Resources as described in Section III.13.1.2.3, except the Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and

the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

III.13.1.3.4. Definition of New Import Capacity Resource.

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

For each New Import Capacity Resource, the Project Sponsor submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the contract period including the entire Capacity Commitment Period, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the

import; or (iv) documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load. For each New Import Capacity Resource, the Project Sponsor must specify the interface over which the capacity will be imported. The Project Sponsor must indicate whether the import is associated with any investment in transmission that increases New England's import capability or is associated with an Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff. The Project Sponsor must submit a contract confirming its association with the Elective Transmission Upgrade Interconnection Customer and the ISO will confirm that relationship. If the import will be backed by a single new External Resource, the Project Sponsor submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Project Sponsor shall instead submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall apply in addition to the requirement that the Project Sponsor submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the Project Sponsor, the description must include a commitment that the External

Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the New Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Project Sponsor shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

If the New Import Capacity Resource will be backed by an external Control Area and the capacity will be imported over an Elective Transmission Upgrade and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall apply in addition to the requirement that the Project Sponsor submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource for the length of the multi-year contract.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.

The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) For imports crossing a single intervening Control Area, the Project Sponsor entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing. (2) For imports crossing more than one intervening Control Area, in addition to the

requirements above, the Project Sponsor entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load. (3) The Project Sponsor entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.13.1.3.5.4. Capacity Commitment Period Election.

The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall only apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request. All other New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction.

III.13.1.3.5.5. Initial Interconnection Analysis.

The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply unless the capacity will be imported over an Elective Transmission Upgrade pursuing Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.3.5.5.A. Cost Information.

The offer information described in Section III.13.1.1.2.2.3 and Section III.A.21.2 may be submitted in the form of a curve (up to five price-quantity pairs) associated with a specific New Import Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources.

In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from New Import Capacity Resources. An offer from a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.1.2.8, a Lead Market Participant with a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade) that submitted a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5 may: (a) lower the requested offer price of any price-quantity pair submitted to the ISO pursuant to Section III.13.1.1.2.2.3, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or (b) withdraw any price-quantity pair of a requested offer price.

III.13.1.3.5.8. Rationing Election.

New Import Capacity Resources are subject to rationing except New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request, which are eligible for the rationing election described in Section III.13.1.1.2.2.3(b).

III.13.1.4. Demand Resources.

III.13.1.4.1. Demand Resources.

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with a Commercial Operation Date before June 1, 2018, or a Demand Response Capacity Resource that cleared in the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period, shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2018. No resource shall be permitted to participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life. Demand Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Resource. Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market Participant for a resource shall include the Enrolling Participant for a Demand Resource.

III.13.1.4.1.1. Existing Demand Resources.

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that

Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.

III.13.1.4.1.2. New Demand Resources.

A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.

For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources

For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for

participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.3. Special Provisions for Real-Time Emergency Generation Resources.

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.4.2. Show of Interest Form for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand

Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor's New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. Qualification Package for Existing Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. Qualification Package for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1. [Reserved.]

III.13.1.4.2.2.2. Source of Funding.

The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3. Measurement and Verification Plan.

For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4. Customer Acquisition Plan.

A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1. Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.

For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.2.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete

III.13.1.4.2.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor's ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor's program to deliver capacity to meet the Demand Resource Project Sponsor's Forward Capacity Auction obligations, and must include each customer's projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor's ability to fulfill its obligation by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource

Project Sponsor shall be subject to the ISO's critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. Capacity Commitment Period Election.

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.2.5.

III.13.1.4.2.2.6. Rationing Election.

The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form.

A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. Offers From New Demand Resources.

All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

III.13.1.4.2.5. Notification of Qualification for Demand Resources.

III.13.1.4.2.5.1. Evaluation of Demand Resource Qualification Materials.

The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

- (a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;
- (b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;

- (c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;
- (d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and
- (e) whether the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.

For each Existing Demand Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type; and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located, and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. Notification of Qualification for New Demand Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.

For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource's summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.

For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.3. Measurement and Verification Applicable to All Demand Resources.

To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects in reducing demand coincident with Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours such that the reported monthly Demand Reduction Value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the Demand Resource project's Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor's total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor's total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Demand Resource Project Sponsors. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and

consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor's offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors shall maintain records of retail customers served including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly Demand Reduction Values. For Demand Resource projects targeting customer

facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor shall maintain records as described above for customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, or shall maintain records of aggregated Demand Reduction Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently delisted from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.

The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation, Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, 2018, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 2018, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity

Commitment Periods commencing on or after June 1, 2018, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2018, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated using the Real-Time Emergency Generation Asset's Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the Retail Delivery Point, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated using the Real-Time Emergency Generations Asset's Average Hourly Load Reduction.

For Capacity Commitment Periods commencing before June 1, 2018, the output of the generators comprising a Real-Time Emergency Generation Asset must be directly metered and reported to the ISO as a single set of interval meter data, provided that if there is no other Real-Time Emergency Generation Asset, Real-Time Demand Response Asset or other generator whose output can be controlled at the same facility, the Market Participant may instead meter the Real-Time Emergency Generation Asset at the retail delivery point. Meter data associated with the Real-Time Emergency Generation Asset shall be recorded and reported by the Market Participant to the ISO in Real-Time at an interval of five minutes.

For Capacity Commitment Periods commencing before June 1, 2018, the output of generators comprising a Real-Time Demand Response Asset located behind the retail delivery point must be directly metered and reported to the ISO in Real-Time as a single set of interval meter data at an interval of five-minutes.

III.13.1.4.3.2.1. No Performance Data to Determine Demand Reduction Values.

Should a new Demand Resource, other than a Demand Response Capacity Resource, enter service at a time such that there is no performance data for June, July, August, December or January upon which to establish summer or winter seasonal Demand Reduction Values, and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, then the summer or winter seasonal Demand Reduction Values will be the simple average of its Demand Reduction Values for those months with a Capacity Supply Obligation. For a new Demand Resource, other than a Demand Response Capacity Resource, that enters service

outside of the summer DR Auditing Period or winter DR Auditing Period and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, the Demand Resource Commercial Operation Audit results shall be used in the determination of the summer or winter seasonal Demand Reduction Value.

III.13.1.4.3.3. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.13.1.4.3.4. Measurement and Verification Costs.

Costs associated with measurement and verification of the Demand Resource project shall be borne by the Demand Resource Project Sponsor. Demand Resource Project Sponsors submitting application materials and Measurement and Verification Documents for review during the Forward Capacity Auction qualification process shall be subject to the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.4.4. Dispatch of Active Demand Resources During Event Hours.

III.13.1.4.4.1. Notification of Demand Resource Forecast Peak Hours.

The ISO shall issue notice to Market Participants concerning Demand Resource Forecast Peak Hours on the day before the relevant Operating Day. The notice issued pursuant to this section is for informational purposes only and shall not constitute a Dispatch Instruction.

III.13.1.4.4.2. Dispatch of Demand Resources During Real-Time Demand Resource Dispatch Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Demand Response Resources to curtail and restore loads during Real-Time Demand Resource Dispatch Hours. Dispatch Instructions shall apply to Real-Time Demand Response Resources. The amount of Demand Resources dispatched for each Real-Time Demand Resource Dispatch Hour will be the amount that the ISO determines is necessary to meet the reserve deficiency. The ISO may issue Dispatch Instructions that reduce or increase the amount dispatched in each hour.

III.13.1.4.4.3. Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Emergency Generation Resources to curtail and restore loads during Real-Time Emergency Generation Event Hours. Dispatch Instructions shall apply to specific Real-Time Emergency Generation Resources. The amount of Real-Time Emergency Generation Resources dispatched for each Real-Time Emergency Generation Event Hour will be the amount the ISO determines is necessary to meet the reserve deficiency.

III.13.1.4.5. Selection of Active Demand Resources For Dispatch.

III.13.1.4.5.1. Management of Real-Time Demand Response Assets and Real-Time Demand Response Resources.

A Market Participant must manage its Real-Time Demand Response Assets that are registered as a component of a Real-Time Demand Response Resource as of the first of a month so that the Real-Time Demand Response Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Demand Response Assets cause, or potentially cause, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to restore the loads of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Demand Response Asset or to restore the load of a dispatched Real-Time Demand Response Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the restoration of that asset. Market Participants with Real-Time Demand Response Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Demand Response Resources consisting of an aggregation of more than one Real-Time Demand Response Asset shall report the load reduction and consumption, or generator output of the resource, to the ISO as the sum of the load reduction, consumption, or generator output of the individual assets making up that resource. Real-Time Demand Response Resources shall be assigned a unique resource identification number. The load reduction and consumption, or generator output of a Real-Time

Demand Response Resource is reported to the ISO as a single set of values. A Real-Time Demand Response Resource shall consist of one or more Real-Time Demand Response Assets that are located within the same Dispatch Zone.

III.13.1.4.5.2. Management of Real-Time Emergency Generation Assets and Real-Time Emergency Generation Resources.

A Market Participant must manage its Real-Time Emergency Generation Assets that are registered as a component of a Real-Time Emergency Generation Resource as of the first of a month so that the Real-Time Emergency Generation Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Emergency Generation Assets causes, or potentially causes, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to discontinue the output of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Emergency Generation Asset or to discontinue the output of a dispatched Real-Time Emergency Generation Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the discontinued output of that asset. Market Participants with Real-Time Emergency Generation Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Emergency Generation Resources consisting of an aggregation of more than one Real-Time Emergency Generation Asset shall report the generator output of the resource to the ISO as the sum of the generator outputs of the individual assets making up that resource. Real-Time Emergency Generation Resources shall be assigned a unique resource identification number. The generator output of a Real-Time Emergency Generation Resource is reported to the ISO as a single set of values. A Real-Time Emergency Generation Resource shall consist of one or more Real-Time Emergency Generation Assets that are located within the same Dispatch Zone.

III.13.1.4.5.3. [Reserved.]

III.13.1.4.6. Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at Dispatch Zones.

III.13.1.4.6.1. Establishment of 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 and dispatch of Demand Response Capacity Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources. Dispatch Zones shall not

change during a Capacity Commitment Period. 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. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.13.1.4.6.2. Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

III.13.1.4.6.2.1. Real-Time Demand Response Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Demand Response Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Demand Response Resource into one or more Real-Time Demand Response Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference, terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.6.2.2. Real-Time Emergency Generation Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Emergency Generation Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Emergency Generation Resource into one or more Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of

the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference, terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.7. **[Reserved.]**

III.13.1.4.8. **[Reserved.]**

III.13.1.4.9. **Restrictions on Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Registration.**

A Market Participant may not register and, if previously registered, must retire in accordance with Section III.13.1.4.9.1, a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

III.13.1.4.9.1. **Requirement for Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Retirement.**

A Market Participant must retire a previously registered Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak

Demand Resource that is comprised of customers specified in subsections (a) or (b) of Section III.13.1.4.9 no later than 12 months from the date that the ISO receives notice that the relevant electric retail regulatory authority prohibits such customer's demand response to be bid into the ISO-administered markets or programs or May 31, 2013, whichever is later.

III.13.1.4.10. Providing Information On Demand Response Capacity, Real-Time Demand Response and Real-Time Emergency Generation Resources.

If requested by a Market Participant with a registered Load Asset, the ISO will provide the following information about end-use customers served by the Market Participant: (a) whether the end-use customer's facility is registered with the ISO as part of an asset and whether the asset is associated with a Demand Response Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource, and; (b) the load reduction capability of the asset, as specified in the ISO's asset registration system, to which the end-use customer's facility is registered.

III.13.1.4.11. Assignment of Demand Assets to a Demand Resource.

The following mapping provisions apply to Demand Resources other than Demand Response Capacity Resources, the mapping for which is addressed in Appendix E to Market Rule 1.

(a) When a demand asset can be mapped to more than one Demand Resource, any demand assets shall be mapped to a commercial Demand Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period, before being mapped to a non-commercial Demand Resource or non-commercial increment of a Demand Resource.

(b) A demand asset cannot be unmapped from a Demand Resource if, following the unmapping, the sum of the audit values of the remaining demand assets that are mapped to the Demand Resource would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides

qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.2.4.5.3. Offers composed of separate resources may not be modified or withdrawn after the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Resource, April through November where the summer resource is a Demand Resource) of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period (October through May where the summer resource is not a Demand Resource, December through March where the summer resource is a Demand Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource or Intermittent Settlement Only Resource. If the winter capacity of the offer composed of separate resources in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

- (d) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone.
- (e) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained.
- (f) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone.
- (g) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource.
- (h) A Renewable Technology Resource may only participate in an offer composed of separate resources if its FCA Qualified Capacity has not been prorated pursuant to Section III.13.1.1.2.10.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than five Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource's final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource's financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the FCM Deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing

Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c) and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity's Capacity Load Obligation in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that

export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

(a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) If a Permanent De-List Bid at or above the Dynamic De-List Bid Threshold or a Static De-List Bid for which an Internal Market Monitor-determined price has not been established, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.13.1.9. Financial Assurance.

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Resources) and New Demand Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the FCM Deposit by the Project Sponsor for a New Generating Capacity Resource or New Demand Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Resource in the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the FCM Deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, financial assurance required prior to the auction pursuant to FAP shall be applied toward the resource's financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity

Auction, the financial assurance required prior to the auction pursuant to FAP will be released pursuant to the terms of the ISO New England Financial Assurance Policy.

III.13.1.9.2. Financial Assurance for New Generating Capacity Resources and New Demand Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Resource's offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Resource: (i) fails to provide the required financial assurance as described in the ISO New England Financial Assurance Policy or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4(c), it shall lose its Capacity Supply Obligation and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. Release of Financial Assurance.

Once a New Generating Capacity Resource or New Demand Resource achieves Commercial Operation and is tested for its capacity rating, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. Forfeit of Financial Assurance.

Where any financial assurance is forfeited pursuant to the provisions of Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to Section III.13 shall be used to reduce charges incurred by load in the relevant Capacity Zone to replace that capacity.

III.13.1.9.2.4. Financial Assurance for New Import Capacity Resources.

A New Import Capacity Resource that is backed by a new External Resource or will be delivered over an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource or the Elective Transmission Upgrade achieves Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. Qualification Process Cost Reimbursement Deposit.

For each New Capacity Show of Interest Form and New Demand Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below (“Qualification Process Cost Reimbursement Deposit”). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project’s critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of

the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff or where a resource modification does not require a revision to the Interconnection Agreement.

<p>New Generating Resources \geq 20 MW or an Import Capacity Resource associated with an Elective Transmission Upgrade that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff</p>	<p>New Generating Resources $<$ 20 MW and \geq 2 MW</p>	<p>Imports and New Demand Resources (including Distributed Generation)</p>		<p>New Generating Resources $<$ 2 MW</p>
<p><i>Including Up-rates, Re-powering, Environmental</i></p>	<p><i>Including Up-rates, Re-powering, Environmental Compliance &</i></p>			

<i>Compliance & Intermittent Power Resources</i>	<i>Intermittent Power Resources</i>			
\$25,000	\$7,500	\$1,000		\$500
<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>	<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>			
\$15,000	\$6500	n/a		n/a

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for Commercial Operation, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s) associated with the qualification process and critical path schedule monitoring, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO’s consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
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For all resources except Demand Resources, Nov. 1, 2006 through Jan. 2, 2007 For Demand Resources, Dec. 18, 2006 through Feb. 28, 2007	Apr. 30, 2007	June 15, 2007	Feb. 4, 2008	June 1, 2010
Sept. 18, 2007 through Nov. 14, 2007	Mar. 14, 2008	Apr. 29, 2008	Dec. 8, 2008	June 1, 2011
July 15, 2008 through Sep. 16, 2008	Feb. 3, 2009	Feb. 17, 2009	Oct. 5, 2009	June 1, 2012
May 15, 2009 through July 14, 2009	Dec. 1, 2009	Dec. 15, 2009	Aug. 2, 2010	June 1, 2013
Mar. 15, 2010 through May 14, 2010	Oct. 1, 2010	Oct. 15, 2010	June 6, 2011	June 1, 2014
Mar. 1, 2011 through Mar. 14, 2011	Aug. 1, 2011	Aug. 15, 2011	Apr. 2, 2012	June 1, 2015
Jan. 3, 2012 through Jan. 17, 2012	June 1, 2012	June 15, 2012	Feb. 4, 2013	June 1, 2016
Feb. 14, 2013 through Feb. 28, 2013	June 3, 2013	June 17, 2013	Feb. 3, 2014	June 1, 2017

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

- (a) each Capacity Commitment Period shall begin in June;
- (b) the New Capacity Show of Interest Submission Window will be in February (after the Forward Capacity Auction for the prior Capacity Commitment Period), approximately four years and three months before the beginning of the Capacity Commitment Period;
- (c) the Existing Capacity Qualification Deadline will be in June just over four years before the beginning of the Capacity Commitment Period;
- (d) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and
- (e) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

The table below shows this generic timeline for the Capacity Commitment Period beginning in year “X”, where X is any year after 2015.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
Feb. (X-4)	June (X-4)	June/July (X-4)	Feb. (X-3)	June X

III.13.1.11 Opt-Out for Resources Electing Multiple-Year Treatment.

Beginning in the qualification process for the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), any resource that had elected in a Forward Capacity

Auction prior to the ninth Forward Capacity Auction (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer cleared may, by submitting a written notification to the ISO no later than the Existing Capacity Qualification Deadline (or, in the case of the ninth Forward Capacity Auction, no later than September 19, 2014), opt-out of the remaining years of the resource's multiple-year election. A decision to so opt-out shall be irrevocable. A resource choosing to so opt-out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.

III.13.5. Bilateral Contracts in the Forward Capacity Market.

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals and Supplemental Availability Bilaterals in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.

A resource having a Capacity Supply Obligation seeking to shed that obligation (“Capacity Transferring Resource”) may enter into a bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part (“Capacity Supply Obligation Bilateral”), to a resource, or portion thereof, having Qualified Capacity for that Capacity Commitment Period that is not already obligated (“Capacity Acquiring Resource”), subject to the following limitations

- (a) A monthly Capacity Supply Obligation Bilateral must be coterminous with a calendar month, and an annual Capacity Supply Obligation Bilateral must be coterminous with a Capacity Commitment Period.
- (b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly Capacity Supply Obligation of the Capacity Transferring Resource during the period covered by the Capacity Supply Obligation Bilateral. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly amount of unobligated Qualified Capacity (that is, Qualified Capacity as determined in the most recent Forward Capacity Auction or reconfiguration auction qualification process that is not subject to a Capacity Supply Obligation for the relevant time period) of the Capacity Acquiring Resource during the period covered by the Capacity Supply Obligation Bilateral, as determined in the qualification process for the most recent Forward Capacity Auction or annual reconfiguration auction prior to the submission of the Capacity Supply Obligation Bilateral to the ISO.
- (c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource’s unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.

(d) A Real-Time Emergency Generation Resource may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource.

(e) [Reserved.]

(f) [Reserved.]

(g) Prior to April 1, 2015, if the Capacity Acquiring Resource is an Import Capacity Resource, then the Capacity Transferring Resource must also be an Import Capacity Resource on the same external interface.

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant Capacity Commitment Period month.

(j) A resource that has not achieved Commercial Operation by the submission deadline for a monthly Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that Capacity Commitment Period month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a Capacity Supply Obligation Bilateral in an amount up to the absolute value of its Capacity Supply Obligation.

III.13.5.1.1. Process for Approval of Capacity Supply Obligation Bilaterals.

III.13.5.1.1.1. Timing of Submission.

The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO before or during submittal windows, as defined in the ISO New England Manuals and ISO New England Operating

Procedures. The ISO will issue a schedule of the submittal windows for annual and monthly Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

III.13.5.1.1.2. Application.

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, in \$/kW-month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of \$0.00/kW-month.

III.13.5.1.1.3. ISO Review.

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral, and shall reject the Capacity Supply Obligation Bilateral if any of the provisions of this Section III.13.5.1 are not met. For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.

(b) After the close of the relevant submittal window, each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards will remain satisfied if the capacity associated with the Capacity Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO's reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved generation or Demand Response Resource outage information, and will include transmission security

studies. The ISO will review all confirmed monthly Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. For a monthly Capacity Supply Obligation Bilateral, the ISO shall obtain and consider information from the Local Control Center regarding whether the Capacity Supply Obligation of the Capacity Transferring Resource is needed for local system conditions and whether it is adequately replaced by the Acquiring Resource.

The ISO will review the net impact of all annual Capacity Supply Obligation Bilaterals to ensure that the regional and local adequacy and other reliability needs achieved through the Forward Capacity Auction are maintained in the Capacity Transferring Resource's Capacity Zone and the Capacity Acquiring Resource's Capacity Zone or across the external interface.

If after its review of the net impact of all annual Capacity Supply Obligation Bilaterals the ISO determines that the regional and local adequacy and other reliability needs achieved through the Forward Capacity Auction are not maintained, and for all monthly Capacity Supply Obligation Bilaterals, the the ISO will approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. If multiple Capacity Supply Obligation Bilaterals are submitted between the same resources, they may be reviewed together as one transaction and the most recent confirmation time among the related transactions will be used to determine the review order of the grouped transaction. Transactions that cannot meet the applicable reliability needs will only be accepted or rejected in their entirety and the resources will not be accepted or rejected in part for purposes of that transaction. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected for reliability reasons the Lead Market Participant or Project Sponsor, as appropriate, for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the reliability need prompting such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

III.13.5.1.1.4. Approval.

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply Obligation of the Capacity Acquiring Resource shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

III.13.5.2. Capacity Load Obligations Bilaterals.

A Market Participant having a Capacity Load Obligation seeking to shed that obligation (“Capacity Load Obligation Transferring Participant”) may enter into a bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone (“Capacity Load Obligation Bilateral”) to any Market Participant seeking to acquire a Capacity Load Obligation (“Capacity Load Obligation Acquiring Participant”). A Capacity Load Obligation Bilateral must be in whole calendar month increments, may not exceed one year in duration, and must begin and end within the same Capacity Commitment Period. A Capacity Load Obligation Transferring Participant will be permitted to transfer, and a Capacity Load Obligation Acquiring Participant will be permitted to acquire, a Capacity Load Obligation if after entering into a Capacity Load Obligation Bilateral and submitting related information to the ISO within the specified submittal time period, the ISO approves such Capacity Load Obligation Bilateral.

III.13.5.2.1. Process for Approval of Capacity Load Obligation Bilaterals.

III.13.5.2.1.1. Timing.

Either the Capacity Load Obligation Transferring Participant or the Capacity Load Obligation Acquiring Participant may submit a Capacity Load Obligation Bilateral to the ISO. All Capacity Load Obligation Bilaterals must be submitted to the ISO in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

III.13.5.2.1.2. Application.

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following : (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.13.5.2.1.3. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section II.13.5.2 are not met.

III.13.5.2.1.4. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral.

III.13.5.3. Supplemental Availability Bilaterals.

A resource's availability score during a Shortage Event may be supplemented by entering into a Supplemental Availability Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. Designation of Supplemental Capacity Resources.

III.13.5.3.1.1. Eligibility.

Generating Capacity Resources that are not Intermittent Power Resources or Settlement Only Resources may be designated as Supplemental Capacity Resources. A Generating Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource's CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales submitted in accordance with Section III.1.10.7(f) from that resource and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource.

III.13.5.3.1.2. Designation.

The designation of a Supplemental Capacity Resource must be made by the resource's Lead Market Participant. The designation shall indicate the term for which the resource is designated as a Supplemental Capacity Resource, which shall be in Operating Day increments, no less than one Operating Day, and no greater than one calendar month. Such designation shall indicate the MW amount being designated as a Supplemental Capacity Resource, and the Capacity Zone in which the resource is located. Such designation must be submitted to the ISO no later than the deadline for the submission of Supply Offers in the Day-Ahead Energy Market for the first Operating Day of the indicated term.

III.13.5.3.1.3. ISO Review.

The ISO shall review the information provided in submission of the designation as a Supplemental Capacity Resource, and shall reject the designation for any of the hours in which any of the provisions of this Section III.13.5.3.1 are not met.

III.13.5.3.1.4. Effect of Designation.

Regardless of whether it ever becomes subject to a Supplemental Availability Bilateral as described in Section III.13.5.3.2, the portion of a resource designated as a Supplemental Capacity Resource is subject to the same energy market offer requirements applicable to a resource having a Capacity Supply Obligation as described in Sections III.13.6.1.1.1 and III.13.6.1.1.2 for Generating Capacity Resources.

III.13.5.3.2. Submission of Supplemental Availability Bilaterals.

The Lead Market Participant for a resource previously designated as a Supplemental Capacity Resource in accordance with the provisions of Section III.13.5.3.1 for a term that included a Shortage Event may submit a Supplemental Availability Bilateral to the ISO assigning all or a portion of its available capability up to its designated supplemental capacity in each hour of that Shortage Event to a Generating Capacity Resource having a Capacity Supply Obligation during that Shortage Event ("Supplemented Capacity Resource"). No other Market Participant may submit a Supplemental Availability Bilateral. The Supplemental Capacity Resource and the Supplemented Capacity Resource must either: (i) be located in the same Reserve Zone (although in no case may a Supplemental Capacity Resource located in an export-constrained Capacity Zone provide supplemental availability outside of that export-constrained Capacity Zone); or (ii) be located in different Reserve Zones such that direction of flow between the Supplemental Capacity Resource and the Supplemented Capacity Resource is counter to any Reserve Zone or Capacity Zone constraint. For purposes of this Section III.13.5.3.2, a Reserve Zone having a locational reserve requirement (established pursuant to Section III.9.2.2) that is less than or equal to zero shall be considered to be unconstrained with respect to the neighboring Reserve Zone. A Supplemental Capacity Resource

may submit Supplemental Availability Bilaterals with multiple Supplemented Capacity Resources, but each MW of supplemental capacity may only be assigned to one Supplemented Capacity Resource. No Supplemental Capacity Resource may itself be a Supplemented Capacity Resource for an hour.

III.13.5.3.2.1. Timing.

A Supplemental Availability Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the month associated with the Supplemental Availability Bilateral, a Supplemental Availability Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Supplemental Availability Bilateral may be revised by the parties to the transaction throughout the resettlement process). A Supplemental Availability Bilateral must be confirmed by the Lead Market Participant for the Supplemented Capacity Resource no later than the same deadline that applies to submission of the Supplemental Availability Bilateral.

III.13.5.3.2.2. Application.

The submission of a Supplemental Availability Bilateral to the ISO shall include the following: (i) the resource identification number for the Supplemental Capacity Resource; (ii) the resource identification number for the Supplemented Capacity Resource; (iii) the MW amount of capacity being assigned from the Supplemental Capacity Resource to the Supplemented Capacity Resource; (iv) the term of the transaction, which shall be in hourly increments coinciding with hourly boundaries, no less than one hour, and no greater than one calendar month.

III.13.5.3.2.3. ISO Review.

The ISO shall review the information provided in submission of the Supplemental Availability Bilateral, and shall reject the Supplemental Availability Bilateral if any of the provisions of this Section III.13.5.3 are not met. The ISO shall reject the applicability of a Supplemental Availability Bilateral in any hour of a Shortage Event unless: (i) the Supplemental Capacity Resource was on-line and following ISO dispatch instructions during that hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is less than or equal to the difference between the Generating Capacity Resource's Economic Maximum Limit as submitted or redeclared by the Lead Market Participant and the Supplemental Capacity Resource's Capacity Supply Obligation or (ii) the Supplemental Capacity Resource was offline for the hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is less than or equal to the difference

between the sum of the Supplemental Capacity Resource's Real-Time Reserve Designations of TMNSR, TMSR and TMOR and the Supplemental Capacity Resource's Capacity Supply Obligation.

III.13.5.3.2.4. Effect of Supplemental Availability Bilateral.

A Supplemental Availability Bilateral does not affect in any way either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Supplemental Availability Bilateral is to modify the Supplemental Capacity Resource's availability score as described in Section III.13.7.1.1.4.

III.13.6. Rights and Obligations.

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. Generating Capacity Resources.

III.13.6.1.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

- (a) the sum of the Generating Capacity Resource's Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours; or
- (b) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a) due to physical design limits, then the resource shall be offered into the Day-Ahead Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero

or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.

III.13.6.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice.

Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the known capability of the resource. A resource failing to comply with this requirement shall be subject to economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.1.3. [Reserved.]

III.13.6.1.1.4. [Reserved.]

III.13.6.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1 and the requirement to provide to the ISO, upon request and as soon as practicable, confirmation of gas volume schedules sufficient to deliver the energy scheduled for each Generating Capacity Resource using natural gas;
- (c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.1.2. Import Capacity Resources.

III.13.6.1.2.1. Energy Market Offer Requirements.

A Market Participant must offer energy associated with an Import Capacity Resource with a Capacity Supply Obligation into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions for every hour of each Operating Day at the same external interface totaling an amount (MW) equal to the Capacity Supply Obligation unless the Import Capacity Resource is associated with an External Resource that is on an outage. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with this requirement may be subject to sanctions pursuant to Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.2 for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.

The offer requirements of Section III.13.6.1.2.1 will not apply to External Transactions associated with the VJO and NYPA Import Capacity Resources specified in Section III.13.1.3.3(c) for the duration of the contract provided the transactions are self-scheduled in both the Day-Ahead Energy Market and Real-Time Energy Market. If the energy associated with these contracts is not self-scheduled, the offer requirements and provisions of this section will apply to the applicable contract.

(a) All priced External Transactions associated with an Import Capacity Resource with a Capacity Supply Obligation must be offered each hour at or below the greater of either: (1) the offer threshold specified in Section III.13.6.1.2.1(b) for the Operating Day; (2) the offer threshold determined for the prior Operating Day; and (3) for any priced External Transactions from the New York Control Area the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface.

(b) A daily offer threshold will be determined for each Operating Day and will apply to each hour of the Operating Day. From June 1, 2010 to May 31, 2013 the daily offer threshold is equal to the product of the PER Proxy Unit heat rate as described in Section III.13.7.2.7.1.1(b)(iii) and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation of day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis. After May 31, 2013 the daily offer threshold is equal to the product of the applicable Forward Reserve Heat Rate as described in Section III.9.6.2 and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven

percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.

(c) Submittal of External Transactions to the Day-Ahead Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource requires submittal of matching energy transactions to the Real-Time Energy Market; the External Transactions submitted to the Real-Time Energy Market must match the External Transactions submitted to the Day-Ahead Energy Market, subject to the right to submit different prices into the Real-Time Energy Market.

(d) External Transactions submitted to the Real-Time Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource must be submitted prior to the offer submission deadline for the Day-Ahead Energy Market the day before the Operating Day for which they are intended to be scheduled.

(e) A Market Participant submitting a priced External Transaction supporting an Import Capacity Resource with a Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must link the transaction to the associated transmission reservation and NERC E-Tag no later than one hour before the operating hour in order to be eligible for scheduling in the Real-Time Energy Market. If a Market Participant does not link the transaction to the associated transmission reservation and NERC E-Tag in the Real-Time Energy Market for any hour during which the External Transaction would otherwise have been economically and reliably scheduled in the Real-Time Energy Market, the associated Import Capacity Resource shall be treated as having not delivered energy for the hour despite ISO requested dispatch under Section III.13.7.1.2 and III.13.7.2.7.2. A Market Participant submitting any other External Transaction to the Real-Time Energy Market must comply with the requirements in Section III.1.10.7(e) with respect to linking the transaction to the associated transmission reservation and NERC E-Tag.

III.13.6.1.2.2. Additional Requirements for Import Capacity Resources.

Import Capacity Resources are subject to the following additional requirements:

(a) information submittal requirements for External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals;

(b) resource backed Import Capacity Resources shall be subject to the outage requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures. Control Area backed Import Capacity Resources are not subject to such outage requirements;

(c) resource backed Import Capacity Resources are subject to the voluntary and mandatory re-scheduling of maintenance procedures outlined in the ISO New England Operating Procedures and ISO New England Manuals.

(d) at the time of submittal, each External Transaction shall reference the associated Import Capacity Resource.

III.13.6.1.3. Intermittent Power Resources.

III.13.6.1.3.1. Energy Market Offer Requirements.

Intermittent Power Resources may submit offers into the Day-Ahead Energy Market. Such resources are required to submit offers for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

III.13.6.1.3.2. [Reserved.]

III.13.6.1.3.3. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.1.4.1. Energy Market Offer Requirements.

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.4.2. Additional Requirements for Settlement Only Resources.

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources having a Capacity Supply Obligation are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals;
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals;
- (c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.5. Demand Resources.

III.13.6.1.5.1. Energy Market Offer Requirements.

Seasonal Peak Demand Resources, On-Peak Demand Resources and Real-Time Emergency Generation Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Markets. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E.

Commencing June 1, 2018, a Market Participant with a Demand Response Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers for its Demand Response Resources into the Day-Ahead Energy Market and Real-Time Energy Market. The sum of the Demand Reduction Offers must be equal to or greater than the Demand Response Capacity Resource's Capacity Supply Obligation whenever the Demand Response Resources are physically available. If the Demand Response Resources are physically available at a level less than the Demand Response Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers will equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand

Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet one of the following requirements:

- (a) the sum of the Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time plus Minimum Reduction Time plus Minimum Time Between Reductions is less than or equal to 72 hours.
- (b) the sum of the Demand Response Resource's Minimum Reduction Time plus the Minimum Time Between Reductions is less than or equal to 24 hours.

III.13.6.1.5.2. Requirement that Offers Reflect Accurate Demand Response Capacity Resource Operating Characteristics.

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a resource Demand Response Resources associated with a Demand Response Capacity Resource must reflect the then-known operating characteristics of the resource. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this requirement shall be subject to economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.5.3. Additional Requirements for Demand Resources.

Demand Resources shall comply with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals and the auditing and rating requirements as detailed in Section III.13.6.1.5.4 and the ISO New England Manuals. Demand Response Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

- (a) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1;
- (b) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.1.5.4. Demand Response Auditing.

Demand Resources shall be subject to ISO conducted audits for the purposes of:

- (a) Auditing Demand Reduction Values or determining the Audited Demand Reduction for a Demand Resource;
- (b) Verifying the Commercial Operation of a Demand Resource; and
- (c) Verifying the Demand Reduction Value or the Audited Demand Reduction of the Demand Resource when the ISO, based on objective criteria, has determined that the Demand Reduction Value or the Audited Demand Reduction of a Demand Resource may not be credible.

New Demand Response Asset Audits shall be performed pursuant to Section III.13.6.1.5.4.8.

III.13.6.1.5.4.1. General Auditing Requirements for Demand Resources Excluding Demand Response Capacity Resources.

- (a) Audits of a Demand Resource will be conducted by simultaneously evaluating the performance of each demand asset that is mapped to that Demand Resource.
- (b) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Real-Time Demand Response Resources containing Real-Time Demand Response Assets that are located behind the same end-use customer meter as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource.
- (c) An audit is valid beginning with the month in which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like seasonal DR Auditing Period. Additional audits performed in a month shall not replace the results of the initial audit conducted in a month and are valid on the first of the subsequent month following the audit. Audit results shall not replace a Demand Reduction Value that is based on Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours.

(d) If one or more demand assets of a Demand Resource do not have audit results at the time the Demand Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those demand assets toward the audit value of the Demand Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit provided the demand asset was available for dispatch by the ISO in that prior month, and if the demand asset was not available for dispatch in that prior month, then the 1st of the month in which the demand asset was available for dispatch.

III.13.6.1.5.4.2. General Auditing Requirements for Demand Response Capacity Resources.

- (a) Audits of Demand Response Resources associated with a Demand Response Capacity Resource will be conducted by simultaneously evaluating the performance of each Demand Response Asset that is mapped to a Demand Response Resource. The Demand Response Resources associated with a Demand Response Capacity Resource are not required to be evaluated simultaneously.
- (b) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Demand Response Resources containing Demand Response Assets that are located behind the same Retail Delivery Point as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource. When the output of the Real-Time Emergency Generation Asset is greater than the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of the Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Net Supply is reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset.
- (c) An audit is valid beginning with the date on which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like Seasonal DR Audit period. For the Capacity Commitment Period commencing on June 1, 2018, the audit results for Demand Response Resources comprised of Demand Response Assets that were associated with a Real-Time Demand Response Resource in the prior Capacity Commitment Period shall be the sum of the audit results for those assets in the prior like Seasonal DR Audit period. When using audit results from a period prior to June 1, 2018 for those former Real-Time Demand Response Assets, the Audited Full Reduction Time shall be 30 minutes.

- (d) If one or more Demand Response Assets of a Demand Response Resource do not have an Audited Demand Reduction at the time the Demand Response Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those Demand Response Assets toward the Audited Demand Reduction of the Demand Response Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit, provided the Demand Response Asset was available for dispatch by the ISO in that prior month, and if the Demand Response Asset was not available for dispatch in that prior month, then the 1st of the month in which the Demand Response Asset was available for dispatch.

III.13.6.1.5.4.3. Seasonal DR Audits.

A Seasonal DR Audit must be conducted for each Demand Resource during each seasonal DR Auditing Period.

III.13.6.1.5.4.3.1. Seasonal DR Audit Requirement.

A Market Participant shall submit each Demand Resource to an ISO initiated audit each season to verify the Demand Reduction Value or Audited Demand Reduction for the resource for one or more months of the season. The Seasonal DR Audit must be requested by the Market Participant for the Demand Resource within each Capacity Commitment Period in which the Demand Resource has a Capacity Supply Obligation. The summer DR Auditing Period begins on June 1 and ends on August 31. The winter DR Auditing Period begins on December 1 and ends on January 31. For all Demand Resources other than Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the audit results for the months of June, July, and August, and audits performed during the winter DR Auditing Period will be used to establish the audit results for the months of December and January. For Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource summer months of June, July, August, September, October, November, and the following April and May, and audits performed during the winter DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource winter months of December and the following January, February and March.

III.13.6.1.5.4.3.2. Failure to Request or Perform an Audit.

If by the 1st of August for the summer DR Auditing Period or by the 1st of January for the winter DR Auditing Period a Market Participant has not requested a Seasonal DR Audit for a Demand Resource, the Market Participant shall be deemed to have requested a Seasonal DR Audit on those respective dates. A Demand Resource that does not successfully perform a Seasonal DR Audit for a DR Auditing Period shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

III.13.6.1.5.4.3.3. Use of Event Performance Data to Satisfy Audit Requirements for Certain Resources.

A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource that has received a Dispatch Instruction in a season for 100% of its highest CSO for the current DR Auditing Period lasting at least one hour, not including the 30 minute Demand Response Resource Notification Time, may use the first 60 minute period of the event after the 30 minute Demand Response Resource Notification Time to satisfy the Seasonal DR Audit requirement for the applicable DR Auditing Period, subject to the provisions of Section III.13.6.1.5.4.1(b). A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource's audit value under this provision is based on the average load reduction or output demonstrated over the duration of the qualifying 60 minute period.

A Market Participant must request that an event be used to satisfy the Demand Resource's Seasonal DR Audit requirement or replace a currently effective audit result within seven days of the Operating Day on which the Dispatch Instruction for the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is received.

III.13.6.1.5.4.3.3.1. Demand Response Capacity Resources.

A Demand Response Capacity Resource may elect to use performance associated with a Capacity Scarcity Condition, or a time period when the ISO has declared a capacity deficiency pursuant to ISO New England Operating Procedure No. 4, that occurs during a DR Auditing Period in place of requesting a Seasonal DR Audit; provided that any Demand Response Asset of a Demand Response Resource associated with the Demand Response Capacity Resource on a forced curtailment or scheduled curtailment as defined in Section III.8B.6 is assessed a zero audit value.

If a Demand Response Resource associated with a Demand Response Capacity Resource does not reduce demand for some portion of the event, the audit results of its Demand Response Assets shall be set to zero. Otherwise, the Demand Response Resources associated with a Demand Response Capacity Resource will be measured based upon their offered parameters per Section III.13.6.1.5.4.6(d), and the

Audited Demand Reduction for each Demand Response Resource will be capped at the average Desired Dispatch Point for the Demand Response Resource over the audit duration by proportionally reducing each associated Demand Response Asset's audit results.

Within 7 calendar days of the event, the participant must inform the ISO that it wishes to use dispatch performance during the event to establish the Demand Response Resource's Audited Demand Reduction.

If an event occurs before a Demand Response Resource has established an Audited Demand Reduction value and the resource was not dispatched during the event at a level equal to its Maximum Reduction, a Market Participant may elect within seven calendar days after the event to set the Audited Demand Reduction of the Demand Response Resource equal to its CLAIM10 or CLAIM30 value at the time of the event as determined pursuant to Section III.9.5.3.

A Market Participant may elect to use performance associated with a CLAIM10 or CLAIM30 audit of a Demand Response Resource that occurs during a DR Auditing Period in place of requesting a Seasonal DR Audit of that resource provided that the audit was conducted in a manner that meets the requirements of a Seasonal DR Audit. Within seven calendar days of the CLAIM10 or CLAIM30 audit, the Market Participant must inform the ISO that it wishes to use dispatch performance during the audit to establish the Demand Response Resource's Seasonal DR Audit value.

III.13.6.1.5.4.4. Demand Resource Commercial Operation Audit.

(a) A Market Participant with a Demand Resource that has one or more increments that have not demonstrated commercial operation prior to the commencement of a Capacity Commitment Period shall perform a Demand Resource Commercial Operation Audit. The results of the Demand Resource Commercial Operation Audit shall be used to verify the commercial capacity of the Demand Resource and establish the Audited Demand Reduction of a Demand Response Resource.

(b) If a Demand Resource Commercial Operation Audit is not performed prior to the commencement of the Capacity Commitment Period, an audit must be requested in time for performance within the first month in which the Demand Resource has a Capacity Supply Obligation in the Capacity Commitment Period or the Commercial Operation Date, whichever is earlier. A Demand Resource that does not successfully perform a Demand Resource Commercial Operation Audit prior to the end of the first month

in which the Demand Resource has a Capacity Supply Obligation shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

(c) A Demand Resource that fails to demonstrate through its Demand Resource Commercial Operation Audit a demand reduction in the amount of its Capacity Supply Obligation shall be subject to the provisions of Section III.13.1.9 and Section III.13.3.4.

(d) A Market Participant may request additional Demand Resource Commercial Operation Audits during a Capacity Commitment Period to verify an increase in the commercial capacity of a Demand Resource.

(e) If a Demand Resource has summer Qualified Capacity, a Demand Resource Commercial Operation Audit must be performed during the summer season (April through November) to verify the commercial capacity of the resource. A Demand Resource Commercial Operation Audit performed during the winter season (December through March) may only be used to verify the winter commercial capacity of the resource.

(f) A Demand Resource Commercial Operation Audit performed during a summer DR Auditing Period or winter DR Auditing Period may be used to satisfy the Seasonal DR Audit requirement for the same seasonal period. If a Demand Resource conducts a Demand Resource Commercial Operation Audit outside of a summer DR Auditing Period or winter DR Auditing Period, the Seasonal DR Audit requirement shall not be satisfied, however the results shall be used in the calculation of the summer Seasonal DR Audit value or winter Seasonal DR Audit value as follows:

- (1) A Demand Resource Commercial Operation Audit conducted in the months of September, October, November, April, or May shall be considered a summer Seasonal DR Audit;
- (2) A Demand Resource Commercial Operation Audit conducted in February or March shall be considered a winter Seasonal DR Audit.

III.13.6.1.5.4.5. Additional Audits.

The ISO may initiate an audit to verify the Demand Reduction Value or Audited Demand Reduction of a Demand Resource when an evaluation based on objective criteria indicates a Market Participant is claiming demand reductions in excess of the Demand Resource's actual capability. Such criteria include, but are not limited to:

- (a) A pattern of submitting to the ISO a level of available interruption that is less than the resource's Demand Reduction Value or Audited Demand Reduction during the same time period;
- (b) Actual loads for the underlying assets of the resource that, when aggregated, are below the resource's Demand Reduction Value or Audited Demand Reduction; or
- (c) Failure to achieve the dispatched interruption.

The results of an additional audit shall replace the results of the last like Seasonal DR Audit or Demand Resource Commercial Operation Audit.

The ISO may perform additional audits for a Demand Resource to establish the audit results or Audited Demand Reduction and the performance of the installed measures of the demand asset or Demand Response Asset. This additional auditing may consist of two levels.

- (a) Level 1 Audit: the ISO will establish the audit results by conducting a review of records of the demand asset or Demand Response Asset to verify that the reported measures have been installed and are operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.
- (b) Level 2 Audit: the ISO shall establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of measures in the demand asset or Demand Response Asset. Such an audit may include a random or select sample of facilities and measures.

A level 1 audit is not required to precede a level 2 audit. If the results of the audit indicate that the demand reduction capability of the Demand Resource is less than or greater than its Demand Reduction Value or Audited Demand Reduction in the same period, then the Demand Reduction Value or Audited Demand Reduction shall be adjusted to the value demonstrated through the audit.

III.13.6.1.5.4.6. Audit Methodologies.

- (a) For On-Peak Demand Resources, audit results shall be established based on the Average Hourly Output or Average Hourly Load Reduction in the DR Auditing Period.
- (b) For Seasonal Peak Demand Resources, audit results shall be established based on Average Hourly Output or Average Hourly Load Reduction or their equivalent in the DR Auditing Period.
- (c) For Real-Time Demand Response Resources and Real-Time Emergency Generation Resources, audits will be conducted via a Dispatch Instruction sent by the ISO. Audit results for a Real-Time Demand Response Resource and Real-Time Emergency Generation Resource will be based on the sum of the average load reductions or average incremental output demonstrated during the audit by each demand asset mapped to the Demand Resource.
- (d) For Demand Response Resources associated with Demand Response Capacity Resources, audits will be conducted via a Dispatch Instruction. Audit results for the Demand Response Resources will be based on the sum of the average demand reductions demonstrated during the audit by each Demand Response Asset associated with the Demand Response Resource that is mapped to the Demand Response Capacity Resource using (i) each Demand Response Resource's Offered Full Reduction Time to establish the start of the audit period and (ii) the Minimum Reduction Time adjusted for ramping time as the audit duration. The Offered Full Reduction Time is the Demand Response Resource Notification Time plus the Demand Response Resource Start-Up Time plus ((the Maximum Reduction minus the Minimum Reduction) divided by the Demand Response Resource Ramp Rate). For purposes of determining the Offered Full Reduction Time, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Maximum Reduction is reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset.

III.13.6.1.5.4.7. Requesting and Performing an Audit.

- (a) Seasonal DR Audits and Demand Resource Commercial Operation Audits will be performed following the request of the Market Participant. Audits will be performed within 20 Business Days of the date requested by the Market Participant. The date and time of the audit will be unannounced. An audit request may be denied by the ISO, and an audit may be rescheduled, if its performance will jeopardize the reliable operation of the electrical system.

(b) Seasonal DR Audits may be performed on different dates and at different times for Demand Response Resources associated with a Demand Response Capacity Resource if the Demand Response Resources have different offer parameters. In addition, the ISO will only schedule Demand Resource Commercial Operation Audits of a Demand Response Resource with Demand Response Assets that do not have an Audited Demand Reduction value.

(c) New Demand Response Asset Audits will be performed following the request of the Market Participant. The request for a New Demand Response Asset Audit by the Market Participant shall be made during the last seven days of the month. The audit will be performed on Business Days during the month following the date of the request by the Market Participant. The date and time of the audit will be unannounced. An audit request may be denied by the ISO, and an audit may be rescheduled, if its performance will jeopardize the reliable operation of the electrical system.

III.13.6.1.5.4.8. New Demand Response Asset Audits

A Market Participant may request a New Demand Response Asset Audit for all New Demand Response Assets that are mapped to a Demand Resource. The results of a New Demand Response Asset Audit may be used:

- (a) In calculating the Seasonal DR Audit value for the Demand Resource to which the asset is mapped until the next Seasonal DR Audit for the full Demand Resource is conducted;
- (b) In calculating the commercial capacity value of the Demand Resource for purposes of determining release of financial assurance pursuant to Section III.13.1.9.2.2, until the next Demand Resource Commercial Operation Audit is conducted;
- (c) For determination regarding termination under Section III.13.3.4(c); and
- (d) In the monthly calculation of a Demand Resource's Demand Reduction Value pursuant to Section III.13.7.1.5.7 and Section III.13.7.1.5.8.

When a New Demand Response Asset Audit is performed, the commercial capacity value and Seasonal DR Audit value of the Demand Resource to which the asset is mapped shall be updated to reflect any changes in the composition of the Demand Resource.

III.13.6.1.5.4.8.1. General Auditing Requirements for New Demand Response Assets.

(a) A New Demand Response Asset Audit will be conducted by simultaneously evaluating the performance of each New Demand Response Asset that is mapped to that Demand Resource.

(b) A New Demand Response Asset Audit is valid beginning with the month in which the audit is performed, and remains valid until the next Seasonal DR Audit is performed for a like season or until a Demand Resource Commercial Operation Audit is performed. Additional audits performed in a month shall not replace the results of the initial audit conducted in a month and are valid on the first of the month following the audit. Audit results shall not be used in the calculation of a Demand Reduction Value that is based on Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours.

III.13.6.1.5.5. Reporting of Forecast Hourly Demand Reduction.

A Market Participant with Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO a two-day forecast of each Demand Resource's Forecast Hourly Demand Reduction for each Operating Day. The Market Participant shall update its forecast, in accordance with the ISO New England Manuals and Operating Procedures, to reflect its estimate of each Demand Resource's Forecast Hourly Demand Reduction.

III.13.6.1.5.6. Reporting of Monthly Maximum Forecast Hourly Demand Reduction.

A Market Participant with Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO each month a forecast of each resource's monthly maximum Forecast Hourly Demand Reduction for each of the next 12 months.

III.13.6.2. Resources without a Capacity Supply Obligation.

A resource that does not have any Capacity Supply Obligation shall comply with the requirements in this Section III.13.6.2, and shall not be subject to the requirements set forth in Section III.13.6.1 during the

Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.13.6.2.1. Generating Capacity Resources.

III.13.6.2.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.1.1.1. Day-Ahead Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offered energy clears in the Day-Ahead Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the operating day, including the obligation to follow ISO dispatch instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.1.2. Real-Time Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, must Self-Schedule in order to participate in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.

Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

- (a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;
- (b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Generating Capacity Resources having no Capacity Supply Obligation are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.2.2. [Reserved.]

III.13.6.2.3. Intermittent Power Resources.

III.13.6.2.3.1. Energy Market Offer Requirements.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.3.2. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals; and
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals.

III.13.6.2.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.2.4.1. Energy Market Offer Requirements.

A Settlement Only Resource may not submit an offer into the Day-Ahead Energy Market or the Real-Time Energy Market.

III.13.6.2.4.2. Additional Requirements for Settlement Only Resources.

Settlement Only Resources are subject to the following additional requirements:

- (a) auditing and rating requirements as detailed in the ISO New England Manuals;
- (b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.2.5. Demand Resources.

III.13.6.2.5.1. Energy Market Offer Requirements.

Real-Time Emergency Generation Resources, Seasonal Peak and On-Peak Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E1. A Market Participant with a Demand Response Resource associated with a Demand Response Capacity Resource without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

For Demand Reduction Offers made into the Day-Ahead Energy Market and Real-Time Energy Market for such Demand Response Resources, the sum of the Demand Response Resource's Minimum Reduction Time plus the Minimum Time Between Reductions must also be less than or equal to 24 hours.

III.13.6.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with a Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response Capacity Resource without a Capacity Supply Obligation, may submit a Demand Reduction Offer into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer, up to the Maximum Reduction offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with a Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response Capacity Resource without a Capacity Supply Obligation, that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit a Demand

Reduction Offer in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.2. Additional Requirements for Demand Response Capacity Resources Having No Capacity Supply Obligation.

Demand Response Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

- (a) complying with the auditing and rating requirements as detailed in Section III.13.6.1.5.4 and the ISO New England Manuals;
- (b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and
- (c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Demand Response Capacity Resources having no Capacity Supply Obligation are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.3. Exporting Resources.

A resource that is exporting capacity not subject to a Capacity Supply Obligation to an external Control Area shall comply with this Section III.13.6.3 and the ISO New England Manuals. Intermittent Power Resources, Settlement Only Resources, and Demand Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7.

III.13.6.4. ISO Requests for Energy.

The ISO may request that a Demand Response Capacity Resource or Generating Capacity Resource having capacity that is not subject to a Capacity Supply Obligation provide energy for reliability purposes in the Real-Time Energy Market, but such resource shall not be obligated under Section III.13 of this Tariff by such a request to provide energy from that capacity, and shall not be subject to any availability penalties under Section III.13 of this Tariff by such a request for failure to provide energy from that

capacity that is not subject to a Capacity Supply Obligation. If such resource does provide energy from that capacity, the resource shall be paid based on its most recent offer and is eligible for NCPC.

III.13.6.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.13.6.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

III.13.7. Performance, Payments and Charges in the FCM.

During each month within each Capacity Commitment Period (“Obligation Month”), each resource that acquired or shed a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will be subject to payments, charges, penalties and adjustments for such activity. In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month shall have their performance measured throughout the month, based on the resource’s availability during any Shortage Events in the Obligation Month.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Performance Measures.

III.13.7.1.1. Generating Capacity Resources.

During each Capacity Commitment Period, each Generating Capacity Resource having a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will have its performance measured during each Obligation Month based on the resource’s availability during any Shortage Events during the month.

III.13.7.1.1.1. Definition of Shortage Events.

(a) In all Capacity Zones, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for Ten-Minute Non-Spinning Reserves shall be a Shortage Event.

(b) Prior to June 1, 2018, in any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for the “minimum TMOR” requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement (described in Section III.2.7A(c)) when Action 2 under Operating Procedure No. 4 has also been implemented for the entire Capacity Zone shall also be a Shortage Event.

(c) Prior to June 1, 2018, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be Action 2 under Operating Procedure No. 4, or any Operating Procedure No. 7 event, that is declared for the entire import-constrained Capacity Zone for thirty or more contiguous minutes and that is not also declared for the entire Rest-of-Pool Capacity Zone.

(d) In all cases, to be considered discrete Shortage Events, such events must be separated by at least 2.5 hours. Events that would satisfy the definition of Shortage Events except that they are separated by less than 2.5 hours shall be considered a single Shortage Event with a duration equal to the sum of the lengths of the underlying events. There shall be no more than two Shortage Events per Capacity Zone per day. If there are more than two Shortage Events in a day, only the first two Shortage Events that occur will be recognized.

(e) For the purposes of Section III.13.7.1.1.1(d), Shortage Events that cross daily boundaries will be considered to occur on the day in which the Shortage Event was triggered. Availability during Shortage Events that cross monthly boundaries will be applied to the Obligation Month in which the Shortage Event was triggered.

III.13.7.1.1.1.A Shortage Event Availability Score.

For each Shortage Event, the ISO shall calculate a Shortage Event Availability Score for each resource, as follows: For each hour containing any portion of the Shortage Event, the ISO shall multiply the resource's hourly availability score by the number of minutes of the Shortage Event in that hour, and then divide the product by the total number of minutes in the Shortage Event. The resulting values for each hour shall then be added together to determine the resource's Shortage Event Availability Score.

III.13.7.1.1.2. Hourly Availability Scores.

The ISO shall calculate an availability score for each resource for each hour that contains any portion of a Shortage Event. A resource's availability score for an hour, expressed as a percentage which may not exceed 100 percent, shall be the sum of the resource's available MW in that hour plus any adjustments pursuant to Section III.13.7.1.1.4 divided by the resource's Capacity Supply Obligation. In the event that there are no Shortage Event hours during a month, no availability penalties will be assessed.

III.13.7.1.1.3. Hourly Available MW.

A resource's available MW in each hour that contains any portion of a Shortage Event shall be determined pursuant to the provisions of this Section III.13.7.1.1.3, provided, however, that in no case

shall a resource's available MW in an hour exceed that resource's CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales from that resource).

(a) For a resource that is on-line with a metered output greater than zero and following ISO dispatch instructions, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(b) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification time plus cold start time of thirty minutes or less, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(c) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification plus cold start-up time of less than or equal to 12 hours (16 hours, during the first five Capacity Commitment Periods for resources with notification plus start-up times greater than 12 hours as of June 16, 2006) and the output, up to the Capacity Supply Obligation, was competitively offered into the Energy Market (i.e., capacity from the listed portion of the resource was offered at or below the appropriate Reference Level plus applicable conduct thresholds) but was not committed by the ISO and was consequently unavailable within 30 minutes, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(d) For a resource that is off-line but not meeting the requirements of either Section III.13.7.1.1.3(b) or Section III.13.7.1.1.3(c), the available MW in an hour shall be zero.

(e) For a resource that is on-line but not able to follow ISO dispatch instructions, the available MW in an hour shall be the resource's metered output for the hour.

(f) Where a resource is not committed due to an outage or derate of transmission equipment within the New England Control Area, other than an outage or de-rate of transmission equipment that is controlled by the owner of the resource or that constitutes a radial lead to a resource in the New England Control Area (other than radial leads to Wyman 4 and Stony Brook), that resource's available MW in an hour shall not be reduced as result. Maine Independence Station shall be considered available when derated or not committed because of a transmission constraint.

(g) Where a resource is denied a self-schedule request by the ISO and therefore was not available in the Real-Time Energy Market, that resource's available MW in an hour shall not be reduced as a result.

(h) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation and cannot conduct its capability audit by the first day of the Obligation Month, that resource's available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(i) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, that resource's available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(j) Where a resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), that resource will have its hourly available MW reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

III.13.7.1.1.4. Availability Adjustments.

(a) A resource's hourly availability score may be increased using a Supplemental Availability Bilateral as described in Section III.13.5.3. Where all of the requirements of Section III.13.5.3 are met, the amount of available MW from the Supplemented Capacity Resource during each hour of the Shortage Event will be increased by the amount of supplemental capacity specified in the Supplemental Availability Bilateral, provided, however, that only available capacity above the Supplemental Capacity Resource's Capacity Supply Obligation, if any, during each hour of the Shortage Event may be counted as supplemental capacity for the Supplemented Capacity Resource. The sum of these amounts will be counted in determining the availability score of the Supplemented Availability Resource for the Shortage Event.

(b) A resource's hourly availability score may be increased when an asset associated with the resource is on a planned outage that was approved in the ISO's annual maintenance scheduling process.

Market Participants may indicate when submitting a planned outage request that the outage is to be considered exempt as described in ISO New England Operating Procedure No. 5. In such cases the associated resource's hourly available MWs may be increased by an amount up to the outage MWs requested, provided that the resource has not exceeded the maintenance allotment hour limit regarding exempt approved planned outages at the time of the Shortage Event as described in the ISO New England Manuals. In the case of a Settlement Only Resource, a planned outage scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource's hourly availability score as described in this subsection.

III.13.7.1.1.5. Poorly Performing Resources.

Prior to the Forward Capacity Auction qualification process, the ISO shall determine whether a resource meets the following two criteria: in the most recent four consecutive Capacity Commitment Periods or the most recent 4 years in which the resource assumed a Capacity Supply Obligation: (a) the resource received 3 annual availability scores of less than or equal to 40 percent; and (b) the resource has failed to be available in its entirety during ten or more Shortage Events during that same period. The annual availability score for each Capacity Commitment Period shall be equal to the average of all availability scores as calculated for each hour during each Shortage Event. If both of these criteria are met, the resource shall be considered a Poorly Performing Resource and shall not be eligible to participate in any subsequent Forward Capacity Auctions, and may not assume an obligation through the reconfiguration auctions, or Capacity Supply Obligation Bilaterals until it either achieves an availability score of 60 percent or higher in three consecutive Capacity Commitment Periods or 3 consecutive years, or demonstrates to the ISO that the reasons for the inadequate availability scores have been remedied. For the purposes of determining whether a resource is a Poorly Performing Resource, its availability score while it is de-listed shall not be considered. For the purposes of returning from poorly performing status, the ISO, at the request of the resource owner, may consider performance while de-listed, but in no case shall the ISO use non-consecutive years for evaluating a resource's performance.

III.13.7.1.2. Import Capacity.

The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as defined in Section III.13.7.1.1.1. An Import Capacity Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1, as appropriate). An Import Capacity Resource's available MW in each hour that contains any portion of a Shortage Event shall be determined as follows:

(a) Where the corresponding External Transactions are delivering energy in accordance with ISO dispatch instructions, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(b) Where the corresponding External Transactions have been offered in accordance with the provisions of Section III.13.6.1.2 and is not delivering energy during the hour because the ISO has not requested dispatch of the transaction, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(c) Where the corresponding External Transactions have not been offered in accordance with the provisions of Section III.13.6.1.2 or have been offered in accordance with the provisions of Section III.13.6.1.2 and are not delivering energy during the hour despite ISO requested dispatch of the transaction, the resource's available MW in the hour shall be zero.

(d) Where the Import Capacity Resource was offered in accordance with the provisions of Section III.13.6.1.2 but cannot make Real-Time deliveries of energy because the relevant external interface is already flowing at its Total Transfer Capability into New England in Real-Time, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

III.13.7.1.2.1. Availability Adjustments.

The hourly availability score of an Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource is on a planned outage in the same manner as described in Section III.13.7.1.1.4(b).

III.13.7.1.3. Intermittent Power Resources.

The performance measure for Intermittent Power Resources, including Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.4. Settlement Only Resources.

III.13.7.1.4.1. Non-Intermittent Settlement Only Resources.

A Non-Intermittent Settlement Only Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively. Its available MW in an hour of a Shortage Event shall be the resource's metered output for the hour.

III.13.7.1.4.2. Intermittent Settlement Only Resources.

The performance measure for Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.5. Demand Resources.

III.13.7.1.5.1. Capacity Values of Demand Resources.

The Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, multiplied by one plus the percent average avoided peak transmission and distribution losses used by the ISO in its calculations of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. Beginning with the Capacity Commitment Period starting June 1, 2012 the Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by one plus the percent average avoided peak transmission and distribution losses used to calculate the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. For the first Forward Capacity Auction, the value of the Installed Capacity Requirement divided by the 50/50 summer system peak load forecast shall be 1.143, and one plus the percent average avoided peak transmission and distribution losses shall be 1.08.

III.13.7.1.5.1.1. Special Provisions for Demand Resources that Cleared in the First through Seventh Forward Capacity Auctions in which Project Sponsor Elected to have its Capacity Supply Obligation and Capacity Clearing Price Apply for Multiple Capacity Commitment Periods.

For a Demand Resource that cleared in the Forward Capacity auction for the Capacity Commitment Period beginning June 1, 2010 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2010, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.143 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2011, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.161 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for any of the Capacity Commitment Periods beginning June 1, 2012 through the Capacity Commitment Period beginning in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply in a future Capacity Commitment Period, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.08. This special provision shall cease to apply once the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.2. Capacity Values of Certain Distributed Generation.

For those Distributed Generation resource assets that are capable of generating energy in excess of the facility load and capable of delivering the excess generation to the power grid, if across Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, as appropriate, a Distributed Generation resource asset's monthly average hourly output is greater than the monthly average hourly load of the end-use customer to which the resource is directly connected, the Capacity Value of the portion of output exceeding the customer's load for the month will be the Demand Reduction Value for that portion of the output. No average avoided peak transmission and distribution losses shall be applied to Net Supply associated with a Demand Response Asset, Demand Response Resource, or Demand Response Capacity Resource.

III.13.7.1.5.3. Demand Reduction Values.

A Demand Reduction Value is a quantity of reduced demand produced by a Demand Resource and is calculated pursuant to Section III.13.7.1.5.4, III.13.7.1.5.5, III.13.7.1.5.6, III.13.7.1.5.7 and III.13.7.1.5.8.

III.13.7.1.5.4. Calculation of Demand Reduction Values for On-Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of On-Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource On-Peak Hours in the month.

III.13.7.1.5.4.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. The summer seasonal Demand Reduction Value shall apply to the months of September, October, November, April and May.

III.13.7.1.5.4.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. The winter seasonal Demand Reduction Value shall apply to the months of February and March.

III.13.7.1.5.5. Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource Seasonal Peak Hours in the month. If there are no Demand Resource Seasonal Peak Hours in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to: (i) the Demand Reduction Value established for the previous month if the previous month's Demand Reduction Value was calculated using Seasonal Peak Hours or (ii) the Seasonal DR Audit results if the Demand Reduction Value for the previous month was not calculated using Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) where there was no audit conducted in the month, the applicable previous seasonal Demand Reduction Value.

III.13.7.1.5.5.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. This summer seasonal Demand Reduction Value will apply to the months of September, October, November, April and May.

III.13.7.1.5.5.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. This winter seasonal Demand Reduction Value will apply to the months of February and March.

III.13.7.1.5.6. [Reserved.]

III.13.7.1.5.6.1. [Reserved.]

III.13.7.1.5.6.2. [Reserved.]

III.13.7.1.5.7. Demand Reduction Values for Real-Time Demand Response Resources.

Demand Reduction Values are determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Demand Response Resource is the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of July, August, or January, the Demand Reduction Value of that resource for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous month's Demand Reduction Value was calculated using Real-Time Demand Response Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Demand Response Event Hours. If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of June or December the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month.

III.13.7.1.5.7.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of a Real-Time Demand Response Resource for September, October, November, April and May shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Values in the most recent months of June, July and August and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of a Real-Time Demand Response Resource for February and March shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of December and January if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Value in the most recent months of December and January and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Demand Response Resource receiving a Dispatch Instruction for a Real-Time Demand Response Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Demand Response Resource's Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Demand Response Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.7.3.1. Determination of the Hourly Real-Time Demand Response Resource Deviation.

An Hourly Real-Time Demand Response Resource Deviation shall be calculated for each Real-Time Demand Response Resource as the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Demand Response Event Hour. The calculation of the Hourly Real-Time Demand Response Resource Deviation shall be determined in a manner that reflects that Real-Time Demand Response Resources are allowed 30 minutes from the beginning of the first Real-Time Demand Response Event Hour in consecutive Real-Time Demand Response Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in the Dispatch Instruction when such resources are dispatched in response to Real-Time Demand Resource Dispatch Hours. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Demand Response Resource Deviation is greater than zero in any Real-Time Demand Response Event Hour, the Hourly Real-Time Demand Response Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Load Zone in the hour or, starting on June 1, 2011, in the same Dispatch Zone in the hour.

III.13.7.1.5.8. Demand Reduction Values for Real-Time Emergency Generation Resources.

Demand Reduction Values shall be determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Emergency Generation Resource shall be the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous months Demand Reduction Value was calculated using Real-Time Emergency Generation Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Emergency Generation Event Hours. If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resource in that month.

III.13.7.1.5.8.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value for the months of September, October, November, April and May shall be equal to the simple average of the Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of September, October, November, April or May, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8, during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value for the months of February and March shall be equal to the simple average of the Demand Reduction Values in the most recent months of December and January if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of February or March, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8 during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Emergency Generation Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Emergency Generation Resource receiving a Dispatch Instruction for a Real-Time Emergency Generation Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the

Real-Time Emergency Generation Resource's Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Emergency Generation Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.8.3.1. Determination of the Hourly Real-Time Emergency Generation Resource Deviation.

An Hourly Real-Time Emergency Generation Resource Deviation shall be calculated for each Real-Time Emergency Generation Resource as the difference between the Average Hourly Output or Average Hourly Load Reduction of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Emergency Generation Event Hour. The calculation of the Hourly Real-Time Emergency Generation Resource Deviation shall be determined in a manner that reflects that Real-Time Emergency Generation Resources are allowed 30 minutes from the beginning of the first Real-Time Emergency Generation Event Hour in consecutive Real-Time Emergency Generation Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in a Dispatch Instruction. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Emergency Generation Resource Deviation is greater than zero in any Real-Time Emergency Generation Event Hour, the Hourly Real-Time Emergency Generation Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the

ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Dispatch Zone in the hour.

III.13.7.1.5.9. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources and Real-Time Emergency Generation Resources Starting with the Capacity Commitment Period beginning June 1, 2012.

Starting with the Capacity Commitment Period beginning June 1, 2012, the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3, which is equal to the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, shall be eliminated from the determination of Hourly Calculated Demand Resource Performance Values, with the exception of Demand Resources that cleared in the Forward Capacity Auctions for the Capacity Commitment Periods beginning June 1, 2010 and June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared. For Demand Resources with such multi-year Capacity Supply Obligations the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3 shall continue to apply until the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources are subject to the availability penalties and credits as defined by their resource type.

III.13.7.2. Payments and Charges to Resources.

Resources acquiring or shedding a Capacity Supply Obligation shall be subject to payments and charges in accordance with this Section III.13.7.2. Such resources will also be subject to adjustments as detailed in Section III.13.7.2.7.

III.13.7.2.1. Generating Capacity Resources.

III.13.7.2.1.1. Monthly Capacity Payments.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

(a) **Forward Capacity Auction.** For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case described in Section III.13.7.1.1.3(i), the lesser of the resource's Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted pursuant to Section III.13.2.7.3(b) (or in the case of Inadequate Supply or Insufficient Competition, the payment rate applicable to that resource under Section III.13.2.8) and as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below (the "FCA Payment"). For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

III.13.7.2.2. Import Capacity.

Import Capacity Resources shall receive monthly capacity payments utilizing the same methodology as that used for Generating Capacity Resources set forth in Section III.13.7.2.1.

III.13.7.2.2.A. Export Capacity.

If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

Charge Amount to Resource Exporting = [Capacity Clearing Price_{location of the interface} - Capacity Clearing Price_{location of the resource}] x Cleared MWs of Export Bid or Administrative Export De-List Bid]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located = [Capacity Clearing Price_{location of the interface} - Capacity Clearing Price_{location of the resource}] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.3.1.

III.13.7.2.3. Intermittent Power Resources.

An Intermittent Power Resource shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section 13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Power Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.4. Settlement Only Resources.

III.13.7.2.4.1. Non-Intermittent Settlement Only Resources.

Non-Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1.

III.13.7.2.4.2. Intermittent Settlement Only Resources.

Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Settlement Only Resource made pursuant to Section III.13.4.2.1.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.5. Demand Resources.

III.13.7.2.5.1. Monthly Capacity Payments for All Resources Except Real-Time Emergency Generation Resources.

For all Demand Resources except for Real-Time Emergency Generation Resources, the monthly payment shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1.

III.13.7.2.5.2. Monthly Capacity Payments for Real-Time Emergency Generation Resources.

For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f).

III.13.7.2.5.3. Energy Settlement for Real-Time Demand Response Resources

A Market Participant with Real-Time Demand Response Assets associated with a Real-Time Demand Response Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E1.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Demand Response Resource is located. The demand reduction paid or charged shall be net of the Real-Time Demand Reduction Obligation of Real-Time Demand Response Assets that are part of the Real-Time Demand Response Resource that received payment pursuant to Sections III.E1.9.2.1 or III.E1.9.2.2 for the same dispatch or audit period. Demand reductions eligible for payments or charges pursuant to

this section shall be those produced during Real-Time Demand Response Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4. Energy Settlement for Real-Time Emergency Generation Resources

A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions or generator output, adjusted as described in Section III.E1.8.3 or III.13.7.2.5.4.1 and for the percent average avoided peak distribution losses for the portion of the asset reducing demand, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing prior to June 1, 2018, and at the Real-Time LMP for the Dispatch Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing on or after June 1, 2018. Demand reductions or generator output eligible for payments or charges pursuant to this section shall be those produced during Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4.1 Adjustment for Net Supply From Real-Time Emergency Generation Assets.

For Capacity Commitment Periods commencing on or after June 1, 2018, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the demand reduction measured at the Retail Delivery Point is first credited to the output of the Real-Time Emergency Generation Asset starting with the Net Supply amount, and any remaining demand reduction is credited to the Demand Response Asset. The Net Supply amount shall not be multiplied by one plus the average avoided peak distribution losses. The demand reduction amount shall be multiplied by one plus the average avoided peak distribution losses.

III.13.7.2.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources shall not receive monthly capacity payments for the portion of the resource designated as a Self-Supplied FCA Resource. Charges to load associated with Self-Supplied FCA Resources are calculated pursuant to Section III.13.7.3.

III.13.7.2.7. Adjustments to Monthly Capacity Payments.

Monthly capacity payments to resources with a Capacity Supply Obligation as of the beginning of the Obligation Month will be adjusted as described in Section III.13.7.2.7.1.

III.13.7.2.7.1. Adjustments to Monthly Capacity Payments of Generating Capacity Resources.

III.13.7.2.7.1.1. Peak Energy Rents.

For Capacity Commitment Periods beginning prior to June 1, 2019, payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents (“PER”) calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone.

III.13.7.2.7.1.1.1. Hourly PER Calculations.

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

$$\text{Hourly PER}(\$/\text{kW}) = [(\text{LMP} - \text{Strike Price}) * [\text{Scaling Factor}] * [\text{Availability Factor}]]$$

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.2.7.1.1.2. Monthly PER Application.

(a) The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as follows:

PER Adjustment = the minimum of: (i) the PER cap or (ii) the Average Monthly PER x PER Capacity Supply Obligation.

Where the PER cap for each resource equals the FCA Payment plus the product of the (1) the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same Capacity Commitment Period and (2) the Capacity Clearing Price as adjusted in Section III.13.2.7.3(b) (or in the case of Inadequate Supply or Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing

Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8) applicable to that resource's location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation calculation.

- (b) PER shall be deducted from capacity payments independently of availability penalties.
- (c) FCA Payment minus PER may not be negative for any month.

III.13.7.2.7.1.2. Availability Penalties.

Availability penalties shall be assessed for each resource with a Capacity Supply Obligation as of the beginning of the Obligation Month. The penalty will be based on the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply or Insufficient Competition, on the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8 in the Capacity Zone in which the resource is located for the relevant Capacity Commitment Period, regardless of whether the resource assumed the Capacity Supply Obligation through a Forward Capacity Auction, a reconfiguration auction, or a Capacity Supply Obligation Bilateral.

For capacity resources that are partially or fully unavailable during a Shortage Event:

- (a) Penalties shall be determined and assessed on a resource-specific basis. Penalties shall be calculated for each Shortage Event during an Obligation Month and assessed on a monthly basis, subject to the availability penalty caps outlined in Section III.13.7.2.7.1.3.
- (b) The penalty per resource for each Shortage Event shall be equal to:
Penalty = [Resource's Annualized FCA Payment]*PF*[1 – Shortage Event Availability Score]

Where:

Annualized FCA Payment = the relevant Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply or Insufficient Competition, the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, multiplied by the resource's Capacity Supply Obligation as of the beginning of the Obligation Month multiplied by 12.

PF = .05 for Shortage Events of 5 hours or less. PF is increased by .01 for each additional hour above 5 hours.

III.13.7.2.7.1.3. Availability Penalty Caps.

The following caps will apply to the total availability penalties assessed to a resource. If a resource with a Capacity Supply Obligation sheds or acquires an obligation outside the relevant Obligation Month, the Annualized FCA Payment shall not be prorated. Caps are resource-specific and partial year assumption or transfer of a Capacity Supply Obligation through Capacity Supply Obligation Bilaterals or reconfiguration auctions does not affect the application of the cap to each resource independently.

- (a) **Per Day.** In no case shall the total penalties for all Shortage Events in an Operating Day exceed 10 percent of a resource's Annualized FCA Payment for that Capacity Commitment Period.
- (b) **Per Month.** The sum of a resource's penalties arising from unavailability during an Obligation Month may not exceed two and one-half times the Annualized FCA Payment, divided by twelve, for that Obligation Month. The sum of a resource's penalties arising from unavailability due to a single outage of four days or less but spanning two calendar months may not exceed two and one-half times the average of the Annualized FCA Payments, divided by twelve, for both months.
- (c) **Per Capacity Commitment Period.** In determining the availability penalties for the Obligation Month, a resource's cumulative availability penalties for a Capacity Commitment Period may not exceed its Annualized FCA Payment (less PER adjustments) for that Capacity Commitment Period.

III.13.7.2.7.1.4. Availability Credits for Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources.

On a monthly basis, penalties received from unavailable resources shall be redistributed to Generating Capacity Resources and Import Capacity Resources with Capacity Supply Obligations and to designated Supplemental Capacity Resources without a Capacity Supply Obligation that have a valid Supplemental Availability Bilateral (pursuant to Section III.13.5.3.2) that were available (pursuant to Section III.13.7.1.1.3) in the respective hours on a Capacity Zone basis as follows: For each Obligation Month, the penalties assessed for the Shortage Events during the month will be credited to those resources identified above that were available, in whole or in part, during the Shortage Events, pro-rata by hourly available MW in the relevant Capacity Zones. Self-Supplied FCA Resources shall be eligible to receive their pro rata share of availability penalties paid by other capacity resources.

III.13.7.2.7.2. Import Capacity.

In addition to the adjustment in this section, Import Capacity Resources shall also be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.2.1. External Transaction Offer and Delivery Performance Adjustments.

In the event that the conditions in Section III.13.6.1.2.1 are not met in any hour of an Operating Day, the Import Capacity Resource will be subject to the following:

(a) If in any hour of an Operating Day a priced External Transaction associated with an Import Capacity Resource with a Capacity Supply Obligation is offered above both the offer threshold for the Operating Day and the offer threshold of the prior Operating Day, and for any priced External Transactions from the New York Control Area also is offered above the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of (1) the Import Capacity Resource's Capacity Supply Obligation and (2) the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), or in the case of Inadequate Supply or Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, divided by the number of days in the month.

(b) For every hour of an Operating Day that the total amount offered from all External Transactions associated with an Import Capacity Resource is less than the Import Capacity Resource's Capacity Supply

Obligation, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the (1) difference between the Capacity Supply Obligation and the total amount of energy offered for that hour and (2) the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), or in the case of Inadequate Supply or Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, divided by the number of hours in the month. For each Operating Day only the greater of the total penalties in either the Day-Ahead Energy Market or Real-Time Energy Market will be assessed. For the purposes of this section the total energy offered will be adjusted in accordance with Section III.13.7.1.1.4(b) for any amount that was unavailable due to an outage approved in the ISO's annual maintenance scheduling process.

(c) Except as specified in Section III.13.7.2.7.2.2, for every hour the total energy from an External Transaction associated with an Import Capacity Resource delivered in real-time to the New England Control Area is less than the energy requested, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of (1) the difference between the quantity requested and the quantity delivered and (2) the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), or in the case of Inadequate Supply of Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, divided by the number of hours in the month.

Any External Transaction associated with an Import Capacity Resource that is determined to be in economic merit during the next-hour scheduling process will be considered a requested transaction and the ISO may request all or a portion of each transaction.

A Market Participant's total penalty amount for a single Operating Day for each Import Capacity Resource shall be no more than the product of (1) the Import Capacity Resource's Capacity Supply Obligation and (2) the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), or in the case of Inadequate Supply of Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, divided by the number of days in the month.

Each Obligation Month the penalty amounts from all Market Participants with Import Capacity Resources will be allocated to all Market Participants based on their pro-rata share of Capacity Load Obligation within each Capacity Zone in the Obligation Month, with each Capacity Zone allocated an amount based on the pro-rata share of total capacity credits within each Capacity Zone.

III.13.7.2.7.2.2. Exceptions.

- a) No penalty will be assessed if the applicable external interface is fully loaded and the energy from an External Transaction that would otherwise be requested cannot flow. If the transfer capability of the applicable external interface is zero in the import direction it will be considered fully loaded for the purpose of this section.

- b) No penalty will be assessed if the delivered energy from a priced External Transaction associated with the New York Control Area is less than requested when the Real-Time Energy Market price at the source location (NYISO Location-Based Marginal Price) is higher than the Real-Time LMP at the associated External Node, provided that Operating Procedure No. 4 has not been declared due to a system-wide capacity deficiency.

- c) No penalty will be assessed during periods when the ISO has taken action to reduce import transactions due to a Minimum Generation Emergency condition or due to ramping constraints.

- d) No penalty will be assessed on the affected external interface during periods when minimum-flow or directional-flow constraints have occurred, when the ISO was unable to utilize the automated check-out processes for the external interface, or when in-hour curtailments have occurred.

III.13.7.2.7.3. Intermittent Power Resources.

Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.4. Settlement Only Resources.

III.13.7.2.7.4.1. Non-Intermittent Settlement Only Resources.

Non-Intermittent Settlement Only Resources are subject to the same PER adjustments and availability penalties as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.4.2. Intermittent Settlement Only Resources.

Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.5. Demand Resources.

III.13.7.2.7.5.1. Calculation of Monthly Capacity Variances.

For each month, the Monthly Capacity Variance of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be calculated by subtracting the Demand Resource's Capacity Supply Obligation for the month from the Demand Resource's monthly Capacity Value. If a Demand Resource's Monthly Capacity Variance is zero, the Demand Resource will not be subject to Demand Resource Performance Penalties or Demand Resource Performance Incentives.

III.13.7.2.7.5.2. Negative Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Demand Resource's Monthly Capacity Variance is a negative value, the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be subject to a Demand Resource Performance Penalty equal to the absolute value of the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply of Insufficient Competition, multiplied by the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, in the Forward Capacity Auction for the relevant Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price, (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply or Insufficient Competition, multiplied by the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8 in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f). If a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to

apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a negative value, the Demand Resource Performance Penalty for such a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be set according to the Capacity Clearing Price applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31, of the year preceding the Capacity Commitment Period applicable to the Demand Resource for the particular Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Demand Resource for the particular Capacity Commitment Period.

III.13.7.2.7.5.3. Positive Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource's Monthly Capacity Variance is a positive value, then the Demand Resource shall be eligible to receive a Demand Resource Performance Incentive based on the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply of Insufficient Competition, multiplied by the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, in the Forward Capacity Auction for the relevant Capacity Commitment Period, or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price, (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply of Insufficient Competition, multiplied by the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same

month in that Capacity Zone. If a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a positive value, then the Demand Resource Performance Incentive for such a Demand Resource shall be set according to the Capacity Clearing Price applicable to the Demand Resource for the particular Capacity Commitment Period (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource for the particulate Capacity Commitment Period in effect as of December 31 of the year preceding the Capacity Commitment Period, provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone.

III.13.7.2.7.5.4. Determination of Net Demand Resource Performance Penalties and Demand Resource Performance Incentives.

Demand Resource Performance Penalties and Demand Resource Performance Incentives shall be determined for each Capacity Zone as follows: if the sum of the Demand Resource Performance Penalties in a month in a Capacity Zone is less than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone, then the total amount of Demand Resource Performance Penalties shall be paid on a pro-rata basis, based on the non-prorated Demand Resource Performance Incentives of each Demand Resource with a positive Monthly Capacity Variance. The total amount of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total amount of the Demand Resource Performance Penalties in the same month in that Capacity Zone.

The total of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total of the Demand Resource Performance Penalties in the same month in that Capacity Zone. If the total Demand Resource Performance Penalties in a month in a Capacity Zone exceeds the total Demand

Resource Performance Incentives in the same month in that Capacity Zone, the difference shall not be collected from load serving entities in that Capacity Zone (the ultimate purchaser of capacity).

III.13.7.2.7.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied, but shall be subject to the availability penalties and caps applicable to their resource types.

III.13.7.3. Charges to Market Participants with Capacity Load Obligations.

A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7.2 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals), less PER adjustments for resources in the zone as defined in Section 13.7.2.7.1.1, adjusted for any Demand Resource Performance Penalties in excess of Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.4, and including any applicable export charges or credits as determined pursuant to Section III.13.7.2.2.A divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.

III.13.7.3.1. Calculation of Capacity Requirement and Capacity Load Obligation.

The ISO shall assign each load serving entity a Capacity Requirement prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals) plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period. The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and

tracking load shifts: load associated with pumping of pumped hydro generators, if the resource was pumping; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as an Asset Related Demand or discrete load asset and is exclusively related to an Alternative Technology Regulation Resource following AGC dispatch instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A load serving entity's Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the Capacity Zone's Capacity Requirement as calculated above and (ii) the ratio of the sum of the load serving entity's annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period to the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period.

A load serving entity's Capacity Load Obligation shall be its Capacity Requirement, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supply FCA Resource designations. A Capacity Load Obligation can be a positive or negative value. A Market Participant that is not a load serving entity shall have a Capacity Load Obligation equal to the net obligation resulting from Capacity Load Obligation Bilaterals, HQICC, and Self-Supply FCA Resource designations.

A Demand Resource's Demand Reduction Value will not be reconstituted into the load of the Demand Resource for the purpose of determining the Capacity Requirement for the load associated with the Demand Resource.

III.13.7.3.1.1. HQICC Used in the Calculation of Capacity Requirements.

In order to treat HQICCs as a load reduction, each holder of HQICCs shall have its Capacity Requirement in the Capacity Zone in which the HQ Phase I/II external node is located as specified in Section III.13.1.3 adjusted by its share of the total monthly HQICC amount.

III.13.7.3.1.2. Charges Associated with Self-Supplied FCA Resources.

The capacity associated with a Self-Supplied FCA Resource shall be treated as a credit toward the Capacity Load Obligation of the load serving entity so designated by such resources as described in

Section III.13.1.6. The amount of Self-Supplied FCA Resources shall be determined pursuant to Section III.13.1.6.

III.13.7.3.1.3. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.3.2. Excess Revenues.

Revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.3.3.

III.13.7.3.3. Capacity Transfer Rights.

III.13.7.3.3.1. Definition and Payments to Holders of Capacity Transfer Rights.

The ISO shall create Capacity Transfer Rights ("CTRs") for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone's Net Regional Clearing Price and absolute value of each Capacity Zone's Capacity Load Obligations, as calculated in Section III.13.7.3.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER and for Demand Resource Performance Penalties net of Demand Resource Performance Incentives.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supply FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supply FCA Resources.

The value of CTRs specifically allocated pursuant to Sections III.13.7.3.3.2(c), III.13.7.3.3.4, and III.13.7.3.3.6 shall be calculated as the product of: (i) the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply or Insufficient Competition, the lower of (1) the Capacity Clearing Price, and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8 for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply or Insufficient Competition, minus the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8 for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. The value of the specifically allocated CTRs will be deducted from the associated Capacity Zone's portion of the CTR fund. The balance of the CTR fund will then be allocated to the load serving entities as set forth in Section III.13.7.3.3.2.

III.13.7.3.3.2. Allocation of Capacity Transfer Rights.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface.** The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface.** Except as provided in Section III.13.7.3.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

(c) **Maine Export Interface.** Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine Export Interface for as long as Casco Bay continues to pay to support the transmission upgrades. Each municipal utility entitlement holder of a resource constructed as a Pool-Planned Unit in Maine shall receive specifically allocated CTRs across the Maine Export Interface equal to the applicable seasonal claimed capability of its ownership entitlements in such unit as described in Section III.13.7.3.3.6. The balance of the CTR fund associated with the Maine Export Interface shall be allocated to load serving entities with a Capacity Load Obligation on the import-constrained side of the Maine Export Interface.

III.13.7.3.3.3. Allocations of CTRs Resulting From Revised Capacity Zones.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.3.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained

Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.3.3.4. Specifically Allocated CTRs Associated with Transmission Upgrades.

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.3.3.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.3.3.2.

III.13.7.3.3.5. [Reserved.]

III.13.7.3.3.6. Specifically Allocated CTRs for Pool Planned Units.

In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive an initial allocation of CTRs equal to the applicable seasonal claimed capability of the ownership entitlements in such unit. Municipal utility entitlements are set as shown in the table below and are not transferrable.

Millstone 3		Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4	Summer (MW)	Winter (MW)
Nominal Summer (MW)	1155.001	1244.275	104.000	100.000	104.000	67.400	65.300	586.725		
Nominal Winter (MW)	1155.481	1244.275	119.000	116.000	119.000	87.400	85.300	608.575		
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%	58.26	63.73
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%	5.04	5.55
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%	2.93	2.37
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%	15.49	15.64
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%	10.40	11.07
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%	57.69	60.26
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%	82.98	92.77
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%	30.53	32.64
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%	4.53	5.22
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%	4.71	5.35
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	7.63	7.63
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%	5.81	6.61
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%	26.40	30.36
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%	17.01	19.33
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%	15.34	16.63
Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%	24.05	24.12

Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%	10.70	12.28
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%	11.67	13.63
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%	36.93	42.17
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%	21.48	24.45
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%	25.58	29.49
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.33	1.33
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%	4.82	5.53
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%	24.33	26.23
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	10.89	10.90
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%	6.60	7.38
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.25	1.25
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%	10.67	12.27
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%	6.97	7.99
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%	10.18	11.69
Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%	67.51	77.27

This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company (“MMWEC”) and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant (“WRC”) any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

III.13.7.3.4. Forward Capacity Market Net Charge Amount.

The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charge; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund; and (d) any applicable export charges.

SECTION III

MARKET RULE 1

APPENDIX E

DEMAND RESPONSE

APPENDIX E1
DEMAND RESPONSE
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APPENDIX E1
DEMAND RESPONSE

1. Demand Response Registration

Appendix E1 applies to Capacity Commitment Periods commencing prior to June 1, 2018.

A Market Participant may register a Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis to provide demand reductions during hours ending 0800 through 1800 on non-Demand Response Holiday weekdays subject to the following conditions:

- (a) the asset is able to produce at least 100 kW of demand reduction, and;
- (b) the metering and communication equipment associated with the asset meets the requirements specified in Section III.E1.2.

A Real-Time Demand Response Asset may consist of an aggregation of multiple end-use metered customers.

1.1 Registration Parameters

During the registration process, Market Participants must submit the following information for each Real-Time Demand Response Asset:

- (a) Maximum Interruptible Capacity;
- (b) Maximum Load, and;
- (c) Maximum Generation, for Real-Time Demand Response Assets that are comprised of Distributed Generation.

1.2 Restrictions on Real-Time Demand Response Asset Registration

A Market Participant may not register and must retire if previously registered a Real-Time Demand Response Asset that is comprised of:

- (a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;
- (b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

A Market Participant may not register an existing Generator Asset as a Real-Time Demand Response Asset for the purpose of submitting Demand Reduction Offers.

2. Metering and Communication

2.1 Interval Metering and Telemetry Requirements

The actual metered demand of each individual end-use customer facility that comprises a Real-Time Demand Response Asset must be measured using interval meters located at the individual end-use customer's retail delivery point and shall be reported to the ISO at an interval of five minutes. Actual metered demand submitted to the ISO shall not include average avoided peak distribution losses.

Interval meters required pursuant to Section III.E1.2.1 must meet the following requirements:

- (a) the interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes;
- (b) if the interval meter is the same meter used by the distribution company for billing purposes, the meter is a revenue-quality meter that is accurate within $\pm 0.5\%$, and;
- (c) if the interval meter is not the same meter used by the distribution company for billing purposes, the interval meter is either a revenue-quality meter that is accurate within $\pm 0.5\%$ or a non-revenue-quality meter with an overall accuracy of $\pm 2.0\%$. For each non-revenue-quality meter used, the Market Participant must, during the registration process, submit certification from the meter

manufacturer that the interval meter being used meets the $\pm 2.0\%$ accuracy threshold, and shall specify accuracy for the following parameters:

- i. current measurement;
- ii. voltage measurement;
- iii. A/D conversion, and;
- iv. calibration.

2.2 Meter Testing

All interval meters must be periodically tested and calibrated.

Market Participants must conduct periodic meter data validation checks.

Market Participants must repair or replace meters that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters and meter data communication systems.

2.3 Auditing

The ISO may, for a Real-Time Demand Response Asset, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and measurement equipment, and witness the demand reduction activities of any facility associated with the asset.

Market Participants must make retail billing meter data from the Host Participant for the facilities associated with a Real-Time Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing, and certifying the metering, data recording and measurement equipment of Real-Time Demand Response Assets.

2.4 Communication/Telemetry

Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facilities comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area. If one or more generators whose output can be controlled is located behind the retail delivery point of the Real Time Demand Response Asset, other than emergency generators that cannot operate synchronized to the electrical grid, then the Market Participant must also submit to the ISO in Real-Time a single set of interval meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

3. Demand Reduction Offers

3.1 Required Demand Reduction Offer Parameters

Market Participants must submit a Demand Reduction Offer for each Real-Time Demand Response Asset that meets the requirements of this section in order to be eligible for a demand reduction payment.

A Demand Reduction Offer must be equal to or greater than the Demand Reduction Threshold Price in effect on the day the Demand Reduction Offer is made.

Demand Reduction Offers reflect the amount of demand reduction offered at the retail delivery point excluding transmission and distribution losses.

A Demand Reduction Offer shall consist of a single offer price in \$/MWh (less than or equal to \$1000/MWh) and a single demand reduction amount (in MW to the nearest 0.1 MW) that shall apply to hours ending 0800 through 1800 in the Operating Day.

A Market Participant may submit a single Demand Reduction Offer for each of its Real-Time Demand Response Assets for each Operating Day that is a non-Demand Response Holiday weekday.

Demand Reduction Offers for the following Operating Day must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the Operating Day and may not be changed thereafter.

The minimum Demand Reduction Offer amount for each Real-Time Demand Response Asset is 100 kW.

The maximum Demand Reduction Offer amount for each Real-Time Demand Response Asset cannot exceed the asset's Maximum Interruptible Capacity.

Market Participants are prohibited from submitting a Demand Reduction Offer for a Real-Time Demand Response Asset for an Operating Day with a scheduled curtailment, or for an Operating Day with a known forced curtailment. If an unanticipated forced curtailment has occurred, Market Participants are prohibited from submitting a Demand Reduction Offer for the affected Real-Time Demand Response Asset for any subsequent Operating Days until the forced curtailment is over and electrical service to the asset has been restored.

3.2 Optional Demand Reduction Offer Parameters

A Demand Reduction Offer may specify a minimum interruption duration of one to four hours. If a Market Participant does not specify a minimum interruption duration in its Demand Reduction Offer, the minimum interruption duration shall be one hour.

A Demand Reduction Offer may specify a curtailment initiation price (in \$ per interruption). If a Market Participant does not specify a curtailment initiation price, the curtailment initiation price shall be \$0.

A Demand Reduction Offer must meet the following minimum and maximum price requirements:

- (a) The offer price not including the curtailment initiation price shall be greater than or equal to the Demand Reduction Threshold Price; and

- (b) The offer cost of the Demand Reduction Offer, which shall include the curtailment initiation price, shall be less than or equal to \$1000/MWh. The offer cost shall be computed as follows: offer cost = offer price + [curtailment initiation price/(minimum interruption duration x bid amount (MW))].

4. Day-Ahead Clearing, Scheduling and Notification

Demand Reduction Offers are cleared after the Day-Ahead Energy Market results are determined.

Demand Reduction Offers are cleared by comparing the Demand Reduction Offer to the hourly Day-Ahead LMPs for the Load Zone in which the Real-Time Demand Response Asset is located. A Demand Reduction Offer associated with a Real-Time Demand Response Asset will clear in one or more hours of the Operating Day if the sum of the hourly Day-Ahead LMP times the Demand Reduction Offer amount in the cleared hours of the Operating Day is greater than or equal to the sum of the curtailment initiation price for the Operating Day and the sum of the Demand Reduction Offer price times the Demand Reduction Offer amount in the cleared hours of the Operating Day.

The ISO will provide Market Participants with demand curtailment schedules for Real-Time Demand Response Assets based on cleared Demand Reduction Offers.

The demand curtailment schedule shall reflect demand reductions (MW) at the Real-Time Demand Response Asset's retail delivery point.

5. Real-Time Scheduling of Demand Reductions

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for the next Operating Day pursuant to Section III.E1.4. If a Market Participant's Demand Reduction Offer is not cleared Day-Ahead to reduce demand in an hourly time interval for the next Operating Day, the Market Participant may initiate a Real-Time demand reduction by reducing demand when the offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which a Real-Time Demand Response Asset is located.

A Market Participant will not receive a Dispatch Instruction in Real-Time for a Real-Time Demand Response Asset.

5.1 Requirements for Demand Reductions of 5 MW and Above

A Market Participant with a Real-Time Demand Response Asset that has submitted a Demand Reduction Offer for the Operating Day, must request permission from the ISO prior to reducing demand in an amount greater than or equal to 5 MW during a 60 minute period, unless the asset was dispatched or audited pursuant to Section III.13. Permission must be requested not less than 15 minutes and not greater than 60 minutes before the start of the demand reduction. The ISO may approve or deny the requested interruption based on the impact of the interruption on system reliability.

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data for the same month of the previous year. The ISO may adjust the offer data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

- i. Each generator and import offer block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.
- ii. An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer block.
- iii. A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.
- iv. A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from demand response exceeds the cost to load associated with compensating demand response.
- v. The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$D RTP = P_{th} \times \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the resulting Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the preceding month in advance of the Demand Reduction Threshold Price's effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Real-Time Demand Response Assets located anywhere within the New England Control Area.

7. Demand Response Baselines

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8A prior to submitting a Demand Reduction Offer for a Real-Time Demand Response Asset.

A Market Participant shall take no actions to establish a Demand Response Baseline or affect a Demand Response Baseline adjustment that results in a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers absent demand reduction payments.

For Real-Time Demand Response Assets comprised of Distributed Generation, a Market Participant shall take no actions to establish a Demand Response Baseline that results in a Demand Response Baseline that reduces the expected output levels of its generation absent demand reduction payments.

8. Real-Time Demand Reduction Obligations

8.1 Real-Time Demand Reduction of Assets Without Generation

The Real-Time demand reduction amount of a Real-Time Demand Response Asset is equal to the difference between its Demand Response Baseline adjusted pursuant to Section III.8A.4 and the asset's Real-Time metered demand, during the intervals that the Real-Time Demand Response Asset was scheduled Day-Ahead by the ISO to reduce demand or was otherwise eligible to receive payment for a demand reduction in Real-Time. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered demand is greater than its adjusted Demand Response Baseline.

8.2 Real-Time Demand Reduction of Assets With Generation

To the extent a generator is located behind the retail delivery point of an individual end-use customer facility that comprises a Real-Time Demand Response Asset, the metered output of the generator in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline. The Real-Time demand reduction amount achieved by the individual end-use customer facility that comprises a Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval minus the sum of the metered demand measured at the retail delivery point and the output of all of the generators located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of all of the generators is greater than its adjusted Demand Response Baseline.

If a Real-Time Demand Response Asset is comprised of a Distributed Generation asset located behind the retail delivery point of an individual end-use customer facility, the interval metered output of the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be used to determine its Demand Response Baseline. The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be equal to the asset's incremental output in each five-minute interval relative to its Demand Response Baseline in the same intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered output is less than its Demand Response Baseline.

8.2.1 Real-Time Demand Reduction of Assets With Generation But With No Other Real-Time Demand Response Asset at that Location

For a Real-Time Demand Response Asset located at a retail delivery point with no other Real-Time Demand Response Assets at or behind the same retail delivery point, the metered output of any Real-Time Emergency Generation Assets in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline.

The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval, calculated pursuant to Section III.8A.4.4, minus the sum of the metered demand measured at the retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of any Real-Time Emergency Generation Assets is greater than its adjusted Demand Response Baseline.

8.3 Treatment of Net Supply

If the metered amount measured at the retail delivery point reflects net energy supply during intervals in which Real-Time Demand Response Assets and/or Real-Time Emergency Generation Assets behind the retail delivery point had positive Real-Time demand reductions, then the amount of net energy supplied in an interval with a positive Real-Time demand reduction shall be subtracted from the Real-Time demand reduction amount in the same interval of each Real-Time Demand Response Asset and/or Real-Time Emergency Generation Asset behind that retail delivery point on a *pro rata* basis. The adjustment for net energy supply shall not result in a negative Real-Time demand reduction amount.

8.4 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Real-Time Demand Response Asset is equal to its Real-Time demand reduction amount adjusted for net supply (limited to 200% of the associated Demand Reduction Offer amount) multiplied by one plus the percent average avoided peak distribution losses.

9. Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Real-Time Demand Response Asset will be paid for its Day-Ahead Demand – Reduction Obligation multiplied by the Day-Ahead LMP for the Load Zone within which the Real-Time Demand Response Asset is located.

9.2 Real-Time Settlement

9.2.1. Real-Time Demand Response Assets with Cleared Demand Reduction Offers

A Market Participant with a Real-Time Demand Response Asset will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the final hourly Real-Time LMP for the Load Zone within which the Real-Time Demand Response Asset is located. The payment for the amount by which the Real-Time Demand Reduction Obligation exceeds the Day-Ahead Demand Reduction Obligation in an hour shall be set to zero if the provisional Real-Time LMP for that hour is less than the Demand Reduction Threshold Price.

A Market Participant will not be charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E1.5.1.

9.2.2. Real-Time Demand Response Assets without Cleared Demand Reduction Offers

If the Demand Reduction Offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which the Real-Time Demand Response Asset is located, the Market Participant will be paid the final hourly Real-Time LMP multiplied by its Real-Time Demand Reduction Obligation.

A Market Participant will not be charged pursuant to Section III.E1.9.2.2 if:

(a) a Demand Reduction Offer does not clear Day-Ahead pursuant to Section III.E1.4, and;

(b) the Real-Time Demand Response Asset produces a negative Real-Time demand reduction amount.

A Market Participant will not be paid for a Real-Time Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E1.5.1.

9.3 Cost Allocation

Payments and charges pursuant to this section will be allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes or incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

10. Average Distribution Losses

For purposes of Section III.E1, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

APPENDIX E2
DEMAND RESPONSE
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APPENDIX E2
DEMAND RESPONSE

Appendix E2 applies to Capacity Commitment Periods commencing on or after June 1, 2018.

1. Demand Response Registration

1.1 Demand Response Resource Registration

A Market Participant may register a Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis and providing Operating Reserve subject to the following conditions:

- (a) each Demand Response Resource must be a single Demand Response Asset or an aggregation of Demand Response Assets located within the same Dispatch Zone and Reserve Zone;
- (b) each Demand Response Resource must be able to produce at least 100 kW of demand reduction;
- (c) the Market Participant must comply with ISO required auditing and testing requirements; and
- (d) the Market Participant must indicate whether it intends to maintain CLAIM10 or CLAIM30 capability for the Demand Response Resource.

A Market Participant may not register a Real-Time Emergency Generation Resource, an On-Peak Demand Resource, a Seasonal Peak Demand Resource or a Dispatchable Asset Related Demand to participate as a Demand Response Resource in the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant may not register a Generator Asset as a Demand Response Asset for the purpose of submitting Demand Reduction Offers. A Market Participant may not register a Demand Response Asset at the same Retail Delivery Point as an existing Generator Asset, and may not register a Generator Asset at the same Retail Delivery Point as an existing Demand Response Asset; provided that this provision shall not apply if the Generator Asset is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

1.2 Demand Response Capacity Resource Registration

A Market Participant may register a Demand Response Capacity Resource subject to the following conditions:

- (a) each Demand Response Capacity Resource must have mapped to it at least one Demand Response Resource within the same Dispatch Zone in order to comply with the energy market offer requirements in Section III.13.6.1.5; and
- (b) a Demand Response Resource cannot be mapped to a Demand Response Capacity Resource, or maintain the mapping to a Demand Response Capacity Resource, if the Demand Response Resource violates the mapping provisions in Section III.E2.1.4(c).

1.3 Demand Response Asset Registration

A Market Participant may register a Demand Response Asset subject to the following conditions:

- (a) Unless it meets the conditions for aggregation in sub-section (b) below, a Demand Response Asset must have a defined, single Retail Delivery Point and be registered at a single Node.
- (b) A Demand Response Asset may be the aggregate demand reduction capability of multiple end-use customers from multiple delivery points within a single Dispatch Zone and Reserve Zone if (i) the demand reduction from each Retail Delivery Point in the aggregation is less than 10 kW, and (ii) the demand at the multiple Retail Delivery Points satisfy the criteria for a homogenous population. A Demand Response Asset that meets these conditions for aggregation must be registered at a single Dispatch Zone and Reserve Zone rather than at a single Node.
- (c) No more than one Demand Response Asset may be located at a single Retail Delivery Point.
- (d) Each Demand Response Asset must be mapped to a Demand Response Resource.
- (e) Each Demand Response Asset must be able to produce at least 10 kW of demand reduction.
- (f) A Demand Response Asset with a registered Maximum Interruptible Capacity equal to or greater than 5 MW from the same Retail Delivery Point must be registered as a single Demand Response Resource at a Node. The evaluation of whether a Demand Response Asset's Maximum Interruptible Capacity is equal to or greater than 5 MW shall account for the most recent seasonal audit results for the assets.
- (g) The metering and communication equipment associated with each Demand Response Asset must meet the requirements in Section III.E2.2.

During the registration process, Market Participants must submit the following for each Demand Response Asset:

- (a) Maximum Interruptible Capacity;
- (b) Maximum Load;
- (c) Maximum Generation, for Demand Response Assets that are comprised of Distributed Generation;
- (d) For a Demand Response Asset capable of producing Net Supply, the Maximum Net Supply permitted under the asset's interconnection agreement; and
- (e) Retail account number and meter number for the end-use customer.

1.4 Restrictions on Demand Response Resource Registration

A Market Participant may not register and must retire if previously registered a Demand Response Resource that is comprised of:

- (a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;
- (b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.
- (c) The Maximum Interruptible Capacity adjusted for the Audited Demand Reduction of each Demand Response Resource registered by a Market Participant within a single Dispatch Zone and Reserve Zone must be at least 1 MW before the Market Participant registers a new Demand Response Resource within that same Dispatch Zone and Reserve Zone. This restriction shall not apply if either:
 - (i) all Demand Response Assets registered by the Market Participant in the Dispatch Zone and Reserve Zone are mapped to a Demand Response Resource mapped to a Demand Response Capacity Resource and the Market Participant wants to register a Demand Response Resource that is not mapped to a Demand Response Capacity Resource; or
 - (ii) all Demand Response Assets registered by the Market Participant in the Dispatch Zone and Reserve Zone are mapped to a Demand Response Resource not mapped to a Demand Response Capacity Resource and the Market Participant wants to register a Demand Response Resource that is mapped to a Demand Response Capacity Resource.

(d) In the event the Audited Demand Reductions of two or more Demand Response Resources registered by a Market Participant within a single Dispatch Zone and Reserve Zone are less than 1 MW following an audit, Demand Response Asset mapping for that Market Participant shall be adjusted if doing so decreases the number of Demand Response Resources within that Dispatch Zone and Reserve Zone.

1.5 Restrictions on Demand Response Asset Mapping

Demand Response Assets may be un-mapped from a Demand Response Resource for re-mapping to another Demand Response Resource, or un-mapped without re-mapping, subject to the following conditions:

- (a) A Demand Response Asset cannot be unmapped from a Demand Response Resource that is mapped to a Demand Response Capacity Resource if, following the un-mapping, the sum of the demand reductions of the remaining Demand Response Assets that are associated with the Demand Response Capacity Resource, as reflected in the most recent seasonal audit for that resource, would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.
- (b) When a Demand Response Asset can be mapped to more than one Demand Response Resource that is mapped to a Demand Response Capacity Resource, a Demand Response Asset shall be mapped to a Demand Response Resource associated with a Demand Response Capacity Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period before being mapped to a Demand Response Resource associated with a non-commercial Demand Response Capacity Resource or non-commercial increment of a Demand Response Capacity Resource.
- (c) A Demand Response Asset may be re-mapped to another Demand Response Resource only if the Audited Full Reduction Time of the asset's new Demand Response Resource, adjusted for the Audited Demand Reduction of the asset's current Demand Response Resource, is equal to or greater than the Audited Full Reduction Time of the Demand Response Resource from which the Demand Response Asset is being un-mapped.
- (d) If a Demand Response Asset is re-mapped to a Demand Response Resource, and the Audited Full Reduction Time of the Demand Response Resource to which the asset is being mapped, adjusted for the Audited Demand Reduction of the Demand Response Resource from which

the asset is being mapped, is less than the Audited Full Reduction Time of the Demand Response Resource from which the asset is being mapped, the Demand Response Asset audit value will be set to zero.

2. Metering and Communication

2.1 Revenue Quality Interval Metering

The metered demand used for settlement purposes of each individual end-use customer facility that comprises a Demand Response Asset must be measured using interval meters located at the individual end-use customer's Retail Delivery Point and shall be reported to the ISO at an interval of five minutes. Metered demand data submitted to the ISO shall not include average avoided peak distribution losses.

The interval meters required pursuant to Section III.E2.2.1 must meet the following requirements:

- (a) The interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes;
- (b) The interval meter can be the same revenue-quality meter used by the distribution company for billing purposes; and
- (c) If the interval meter is not the same revenue-quality meter used by the distribution company for billing purposes, the Market Participant must validate and provide documentation to the ISO that the difference between the values recorded by the Market Participant's meter in each interval and the value recorded by the distribution company's billing meter in the same interval is within $\pm 2.0\%$; provided that, if accurate interval data from the distribution company are not available, the Market Participant shall validate that the difference between the sum of the values recorded by the Market Participant's meter and the sum of the values recorded by the distribution company's billing meter over the same time period is within $\pm 2.0\%$; and further provided that the Market Participant specifies the meter manufacturer and model, and the accuracy for the following parameters:
 - i. current measurement;
 - ii. voltage measurement;
 - iii. A/D conversion; and
 - iv. calibration.

- (d) The Market Participant shall provide documentation to the ISO of any inaccuracies found in distribution company meter data and of any communications with the distribution company to address the meter data inaccuracies.

2.2 Communication/Telemetry

Market Participants must report in Real-Time to the ISO a single set of telemetry data for each individual end-use customer facility that comprises a Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of the Demand Response Asset as measured at the Retail Delivery Point, and shall be reported to the ISO every five minutes. For a Demand Response Resource to provide Ten Minute Spinning Reserve or Ten Minute Non-Spinning Reserve, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

The Market Participant must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions.

If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of telemetry data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

The telemetry measurement device used to measure the real-time demand and any Net Supply pursuant to Section III.E2.2.2 must have an overall accuracy of $\pm 2.0\%$. If the Market Participant is not using the meter used by the distribution company for billing purposes to obtain the real-time telemetry, then the Market Participant must specify the device manufacturer and model, and submit certification from the

measurement device manufacturer that the device being used meets the $\pm 2.0\%$ accuracy threshold, and shall specify the accuracy for the following parameters:

- i. current measurement;
- ii. voltage measurement;
- iii. A/D conversion; and
- iv. calibration.

2.3 Testing of Meters and Telemetry Measurement Devices

All interval meters and telemetry measurement devices must be periodically tested and calibrated.

Market Participants must conduct periodic meter and telemetry data validation checks.

Market Participants must repair or replace meters or telemetry measurement devices that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters, telemetry measurement devices, and data communication systems.

2.4 Auditing

The ISO may, for Demand Response Resources, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset.

Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing and certifying the metering, data recording and telemetry measurement equipment of Demand Response Assets.

3. Day-Ahead Energy Market Demand Reduction Offers

Market Participants must submit a Demand Reduction Offer for each Demand Response Resource that meets the requirements of this section in order to be eligible for a payment for a demand reduction.

The Market Participant's Demand Reduction Offer for a Demand Response Resource must satisfy the following conditions:

- (a) Demand Reduction Offers must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the applicable Operating Day.
- (b) The Market Participant can submit up to 10 monotonically increasing price/demand reduction amount pairs for each Operating Day. The demand reduction amount shall not include an adjustment for average avoided peak transmission and distribution losses.
- (c) The minimum amount for each price/demand reduction amount pair of a Demand Reduction Offer is 100 kW.
- (d) The sum of all price/demand reduction amount pairs for a Demand Reduction Offer cannot exceed the sum of the Maximum Interruptible Capacities of the resource's Demand Response Assets.
- (e) The minimum Demand Reduction Offer price must be equal to or greater than the Demand Reduction Threshold Price in effect for the day the Demand Reduction Offer is submitted.
- (f) The maximum Demand Reduction Offer price must be less than or equal to the Energy Offer Cap.

Market Participants may not Self-Schedule interruptions in the Day-Ahead Energy Market.

3.1 Required Demand Reduction Offer Parameters

The Market Participant shall provide the following hourly values in its Demand Reduction Offer. The Market Participant shall maintain up-to-date values for each of these parameters prior to and throughout the Operating Day:

- (a) Available or Unavailable;
- (b) Minimum Reduction (MW), and;
- (c) Maximum Reduction (MW).

3.2 Optional Demand Reduction Offer Parameters

The Market Participant may also specify the following in its Demand Reduction Offer:

- (a) Interruption Cost (\$)
- (b) Minimum Reduction Time (Hrs)
- (c) Minimum Time Between Reductions (Hrs)
- (d) Demand Response Resource Start-Up Time (Hrs)
- (e) Demand Response Resource Notification Time (Hrs)
- (f) Demand Response Resource Ramp Rate (MW/min)

- (g) Offered CLAIM10 (MW)

- (h) Offered CLAIM30 (MW)

4. Real-Time Energy Market Demand Reduction Offers

During the Re-Offer Period, Market Participants may submit revisions to the price or demand reduction amount parameters of a Demand Reduction Offer. Demand Response Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices.

Revisions to Demand Reduction Offers during the Re-Offer Period are subject to the following conditions that apply to Day-Ahead Demand Reduction Offers under Section III.E2.3: limitation to 10 monotonically increasing price/demand reduction amount pairs, minimum amount, maximum amount, minimum price and maximum price.

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for that Operating Day pursuant to Section III.E2.5 or modified during the Re-Offer Period.

No changes will be allowed to the Demand Reduction Offer after the close of the Re-Offer Period. Market Participants may not Self-Schedule interruptions in the Real-Time Energy Market.

5. Scheduling and Dispatching

The ISO shall schedule in the Day-Ahead Energy Market and schedule and dispatch in the Real-Time Energy Market the Demand Response Resource as specified in Section III.1.7.6(a).

At the conclusion of the Day-Ahead Energy Market clearing, the ISO will provide Market Participants with Day-Ahead demand reduction schedules for Demand Response Resources reflecting demand reduction amounts that do not include average avoided peak transmission and distribution losses for each hour of the following Operating Day.

During the Operating Day, the ISO will issue Dispatch Instructions to the Market Participant specifying the expected demand reduction amount that does not include average avoided peak transmission and distribution losses from their Demand Response Resource and the Dispatch Rate.

A Market Participant must notify the ISO, as soon as practicable, of a facility or generator shutdown or equipment outage (including partial outages) that reduces the Demand Response Resource's ability to achieve the demand reduction reflected in the Demand Reduction Offer for an Operating Day.

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data for the same month of the previous year. The ISO may adjust the offer data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

- (a) Each generator and import offer block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.
- (b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer block.
- (c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

- (d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from demand response exceeds the cost to load associated with compensating demand response.
- (e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} \tilde{A} - \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the resulting Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the preceding month in advance of the Demand Reduction Threshold Price's effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Demand Response Resources located anywhere within the New England Control Area.

7. Real-Time Demand Reduction Obligation

A Demand Response Resource's Real-Time Demand Reduction Obligation will be calculated for each dispatch interval in which the Demand Response Resource receives a Dispatch Instruction to reduce demand.

7.1 Real-Time Demand Reductions

The Real-Time demand reduction in a dispatch interval is the difference between the adjusted Demand Response Baseline, further adjusted for any metered output for a Real-Time Emergency Generation Asset

located at the same Retail Delivery Point, and the metered demand for each Demand Response Asset associated with the Demand Response Resource.

If a Market Participant receives a Dispatch Instruction for a Demand Response Resource to reduce demand in a dispatch interval by zero MW, then in calculating the Real-Time Demand Reduction Obligation of the Demand Response Resource the Real-Time demand reductions of the Demand Response Assets comprising the resource shall be equal to zero for that dispatch interval.

7.2 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Demand Response Resource is the sum of the hourly integrated Real-Time demand reduction amounts of the Demand Response Assets comprising the Demand Response Resource, multiplied by one plus the percent average avoided peak distribution losses, except that any Net Supply produced by the Demand Response Assets comprising the Demand Response Resource will not be adjusted by average avoided peak distribution losses.

If a Market Participant fails to comply with the metering and communication requirements in Section III.E2.2 for a Demand Response Resource for any period of time, then the Real-Time Demand Reduction Obligation shall be zero for that period of time.

8. Demand Response Resource Baseline

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8B prior to submitting a Demand Reduction Offer for a Demand Response Resource, and must comply with the requirements for maintaining and resetting the Demand Response Baseline as set forth in Section III.8B.

A Market Participant shall not take actions to create or maintain a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers in the absence of demand reduction payments.

9. Energy Market Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Demand Response Resource will be paid for its Day-Ahead Demand Reduction Obligation multiplied by the Day-Ahead LMP for the Dispatch Zone or Node at which the resource is registered.

9.2 Real-Time Settlement

A Market Participant with a Demand Response Resource will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the hourly Real-Time LMP for the Dispatch Zone or Node at which the resource is registered.

9.3 Cost Allocation

Charges or payments resulting from Real-Time demand reductions produced by Demand Response Resources or Real-Time Emergency Generation Resources shall be allocated on an hourly basis proportionally to Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

9.4 NCPC Credits and Charges

A Market Participant with a Demand Response Resource is eligible for NCPC credits if the resource is following Dispatch Instructions. A Market Participant with a Demand Response Resource is ineligible for NCPC credits and may be assessed NCPC charges if the resource is not operating within the acceptable dispatch tolerance. A resource is not operating within the acceptable dispatch tolerance if in any five-minute interval for an hour the resource is not operating within 10% above or below the resource's Dispatch Instruction, except that a Market Participant with a resource that is not operating within the acceptable dispatch tolerance will not be assessed NCPC charges if during the entire hour the resource operates within 5% above or below the resource's Dispatch Instruction.

10. Average Avoided Peak Distribution Losses

For purposes of Section III.E2, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**ISO New England Inc. and
New England Power Pool**

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Docket No. ER16-____-000

TESTIMONY OF HENRY Y. YOSHIMURA

1 **I. IDENTIFICATION OF WITNESS**

2 **Q: Please state your name, title, and business address.**

3 A: My name is Henry Y. Yoshimura. I am the Director of Demand Resource Strategy for
4 ISO New England Inc. (the “ISO”), One Sullivan Road, Holyoke, Massachusetts
5 01040-2841.

6

7 **Q: Please summarize your job responsibilities.**

8 A: I am responsible for the development of demand resource initiatives for the New
9 England wholesale electricity market and I assist ISO business units in implementing
10 these initiatives.¹ I manage the ISO’s Demand Resource Strategy Department to
11 develop programs and market designs that integrate demand resources into the
12 wholesale capacity, energy, and ancillary service markets. In this capacity, I work with
13 the ISO’s Market Design group under the direction of Mr. Mark Karl, the Vice

¹ Capitalized terms used but not defined in this testimony are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the “ISO Tariff”), the Second Restated New England Power Pool Agreement, and the Participants Agreement. The market rules are contained in Section III of the ISO Tariff.

1 President of Market Development, and work with external and internal stakeholder
2 groups (*e.g.*, Market Participants, New England Power Pool (“NEPOOL”) Participants,
3 state and Federal regulators, and the ISO’s Market and System Operations, Planning,
4 Settlements, and IT Departments) to successfully implement such programs and market
5 designs.

6
7 I also serve on the Board of Directors of the Association for Demand Response and
8 Smart Grid (“ADS”). ADS is a nonprofit organization consisting of policymakers,
9 utilities, system operators, technology companies, consumers, and other stakeholders
10 involved in the demand response and smart grid space. ADS facilitates the exchange of
11 ideas, information, and expertise to help its members advance the deployment of
12 demand response and a smarter grid.

13
14 Finally, I serve as the Chair of the Demand Resources Working Group (“DRWG”),
15 which is a standing working group of the NEPOOL Markets Committee that reviews
16 proposed changes to the market rules and manuals pertaining to demand resources as
17 directed by the NEPOOL Markets Committee. The DRWG also provides a forum for
18 stakeholders and the ISO to exchange ideas and information on topics such as: demand
19 resource program implementation, business process improvements, marketing
20 activities, administrative or operational problems and issues relating to the participation
21 of demand resources in the wholesale electricity markets, and the results of analyses
22 concerning demand resource performance.

23

1 I have appeared before the Federal Energy Regulatory Commission (the
2 “Commission”) on behalf of the ISO on several occasions addressing demand response
3 in organized electricity markets. Specifically, I appeared before the Commission in
4 technical conferences on Demand Response in Organized Electric Markets held on
5 April 23, 2007 in Docket No. AD07-11-000 and May 21, 2008 in Docket No. AD08-8-
6 000, and concerning the National Action Plan on Demand Response held on November
7 19-20, 2009 in Docket No. AD09-10-000. I have sponsored testimony on demand
8 resource topics on behalf of the ISO many times.

9
10 **Q: Please summarize your experience and qualifications.**

11 A: I joined the ISO in 2002. Before joining the ISO, I spent approximately two years in
12 Jakarta, Indonesia with the Institute of International Education as the Chief of Party of a
13 USAID-sponsored project in which I led and mentored a group of Indonesian staff to
14 advise and assist the Government of Indonesia to restructure the Indonesian electricity
15 sector and set up appropriate regulatory institutions.

16
17 Before my assignment in Indonesia in 2000, I was a Senior Consultant of Economics
18 and Public Policy for XENERGY Consulting, Inc., where I managed a variety of
19 projects related to electric industry restructuring in the United States. Before joining
20 XENERGY in 1997, I was a Senior Consultant with La Capra Associates, where I
21 helped several electric and gas utilities evaluate the cost-effectiveness of demand-side
22 management options for inclusion in their integrated resource plans. I also advised the
23 Massachusetts Division of Energy Resources (“DOER”) in a series of proceedings

1 including the Massachusetts Department of Public Utilities' ("DPU") rulemaking
2 concerning electric industry restructuring and assisted the DOER in settlement
3 negotiations with Massachusetts utilities concerning the structure of their restructuring
4 plans.

5
6 Before joining La Capra Associates in 1992, I served on the staff of the DPU for about
7 ten years and held several positions including Senior Economist, Assistant Director of
8 the Electric Power Division, and Director of the Electric Power Division. As Director
9 of the DPU's Electric Power Division, I guided the regulatory effort that made
10 Massachusetts among the first states to integrate energy efficiency into the utility
11 planning, resource acquisition, and ratemaking processes. Additionally, I managed
12 staff working in the areas of utility cost of service and rate design, and integrated
13 resource planning. I participated in the development of numerous regulatory policies
14 such as marginal cost-based rate design, cost recovery standards for utility generation,
15 competitive bidding regulations for non-utility generation, integrated resource
16 management, and the incorporation of environmental externalities in utility integrated
17 resource plans.

18
19 I have bachelor and graduate degrees in economics from the University of Montana.

20 Including my work in graduate school, which was in the energy field, I have about 30
21 years of domestic and international experience as an economist and public policy expert
22 in the electric power industry.

23

1 **II. PURPOSE OF TESTIMONY**

2 **Q: What is the purpose of this testimony?**

3 A: The purpose of this testimony is to explain three sets of market rule changes, all of
4 which directly affect demand response resources participating in the New England
5 wholesale markets. The three sets of changes are:

- 6 1) delaying the full integration of demand response into the wholesale markets by
7 one year;
8
9 2) revising the methodology used to derive Demand Response Baselines; and
10
11 3) modifying the simultaneous auditing requirement of Real-Time Demand
12 Response and Real-Time Emergency Generation Resources.
13

14 **III. DELAYING THE FULL INTEGRATION OF DEMAND RESPONSE INTO THE**
15 **WHOLESALE MARKETS BY ONE YEAR**

16 **Q: What does the “full integration” of demand response into the wholesale markets**
17 **entail?**

18 A: The full integration of demand response into the wholesale markets refers to the ISO’s
19 plan to enable Demand Response Resources to:

- 20 1) ***Fully participate in the Day-Ahead and Real-Time Energy Markets:*** this would
21 be accomplished by enabling Demand Response Resources to submit Demand
22 Reduction Offers into the Day-Ahead and Real-Time Energy Markets, which would
23 be used to optimally commit and dispatch such resources in conjunction with all
24 other energy resources such as Generator Assets.²

² The full participation of Demand Response Resources in the Day-Ahead and Real-Time Energy Markets is the second stage of a two-stage implementation process, which was proposed by the ISO to comply with Order No. 745. The Commission largely accepted the ISO’s proposal in the following orders: *ISO New England Inc.*, 138 FERC ¶ 61,042 (2012) (order on the ISO’s Order No. 745 Compliance Filing); *ISO New England Inc. and New England Power Pool*, Docket No. ER12-947-000 (Apr. 17, 2012) (delegated letter order accepting the ISO’s Demand Response FCM Conforming Changes); *ISO New England Inc. and New England Power Pool*, Docket No. ER12-1550-000 (May 29, 2012) (delegated letter order accepting the ISO’s Market Rule 1 Clarifications to the Transition Period Rules for Demand Response); *ISO New England Inc.*, 142 FERC ¶ 61,027 (2013) (order on the ISO’s Market Rule 1 Demand Response FCM Conforming Changes for Full Integration); and *ISO New England Inc.*, 144 FERC ¶ 61,140 (2013) (order on the ISO’s Market Rule 1 Clarifications to the Full Integration Rules for Demand Response and Revisions to Address the Treatment of Net Supply).

1 2) ***Provide Operating Reserve and participate in the Forward Reserve Market:*** once
2 Demand Response Resources are integrated into the Energy Markets, Demand
3 Reduction Offers in conjunction with all other Energy Market Supply Offers will be
4 used to co-optimally dispatch and designate Resources to provide Energy and
5 Operating Reserve so as to produce the most economically efficient outcome to
6 meet both energy and reserve requirements. Expanding the potential for additional
7 resources to supply comparable Energy and Operating Reserve services in real time
8 and on a forward basis can provide for a more reliable electric system and increase
9 competition among the suppliers of those services.³

10
11 3) ***Receive obligations and compensation in the capacity market that are fully***
12 ***comparable with those of dispatchable generation resources:*** with the integration
13 of Demand Response Resources into the energy and reserves markets, all
14 dispatchable resources participating in the capacity market would be subject to and
15 can receive fully comparable obligations and compensation in the capacity market,
16 which reduces potential market distortions.⁴
17

18 **Q: Why is the ISO proposing to delay the full integration of demand response into the**
19 **wholesale markets by one year?**

20 **A:** In compliance with the Commission’s Order No. 745, the ISO Tariff currently requires
21 that full integration be implemented by June 1, 2017. However, a one-year delay is
22 needed to address the uncertainty created by the decision of the U.S. Court of Appeals
23 for the District of Columbia Circuit (“D.C. Circuit”) vacating Order No. 745,⁵ which is
24 being reviewed by the U.S. Supreme Court.⁶
25

³ The Commission accepted Tariff revisions to fully integrate Demand Response Resources into the reserve markets in *ISO New England Inc. and New England Power Pool*, 150 FERC ¶ 61,007 (2015).

⁴ The Commission accepted the ISO’s Tariff revisions to conform the FCM rules with the rules providing for full integration of Demand Response Resources into the wholesale markets in the following orders: *ISO New England Inc.*, 142 FERC ¶ 61,027 (2013) (as corrected by errata notice issued January 15, 2013); and *ISO New England Inc.*, 146 FERC ¶ 61,175 (2014).

⁵ *Electric Power Supply Association v. FERC*, 753 F.3d 216. (D.C. Cir. 2014) (“*EPSA*”).

⁶ See *FERC v. Electric Power Supply Association*, No. 14-840, 135 S. Ct. 2049 (May 4, 2015); *EnerNOC, Inc. v. Electric Power Supply Association*, No. 14-841, 135 S. Ct. 2049 (May 4, 2015).

1 Key to the full integration of demand response into all of the wholesale markets is the
2 integration of Demand Response Resources into the Energy Markets. Without Energy
3 Market integration, not only would Demand Response Resources not be able to
4 participate in the Energy Markets, but these resources also would not be able to provide
5 Operating Reserves (on either a real-time or forward basis), given that Energy Market
6 offers are used to designate and compensate specific resources providing reserves.
7 Furthermore, if Demand Response Resources cannot participate in the Energy Markets,
8 their capacity market obligations and compensation cannot be made fully comparable
9 with those of dispatchable generation resources – for example, if Demand Response
10 Resources were prohibited from Energy Market participation, the requirement that
11 resources with a Capacity Supply Obligation (“CSO”) must participate in the Energy
12 Markets, which is applied to generation resources with a CSO,⁷ could not be applied to
13 Demand Response Resources.⁸ Therefore, if the U.S. Supreme Court upholds the D.C.
14 Circuit’s order vacating Order No. 745, Demand Response Resource participation in
15 the Energy Markets as currently envisioned in the ISO Tariff would not be permitted,
16 which makes full integration as described above impossible.

17
18 Under the circumstances, therefore, prudent resource management requires that full
19 integration be delayed by one year. Since a final decision by the U.S. Supreme Court
20 will likely be issued by June 2016 and since full integration will take about two years to
21 implement, a one-year delay should give the ISO sufficient time to implement full

⁷ See ISO Tariff Section III.13.6.1.1.1.

⁸ See ISO Tariff Section III.13.6.1.5.1.

1 integration by June 1, 2018 if the U.S. Supreme Court reverses the D.C. Circuit and
2 upholds Order No. 745. If, on the other hand, the U.S. Supreme Court agrees with the
3 D.C. Circuit and Order No. 745 is vacated, the one-year delay would allow the ISO and
4 the region to avoid an unnecessary expenditure of resources to meet the current ISO
5 Tariff requirement that full integration be implemented on June 1, 2017. Full
6 integration is a very resource-intensive process requiring significant modifications to
7 energy and reserve market software, infrastructure, and business procedures. To meet
8 the June 1, 2017 implementation date, the ISO and the region would need to be actively
9 changing its systems now – but that effort would be wasted if Order No. 745 were
10 vacated following review by the U.S. Supreme Court. Such potential wasted effort can
11 be completely avoided by delaying full integration and proceeding with future
12 development activities after the U.S. Supreme Court issues its opinion, which is
13 expected by June 2016.

14
15 **Q: What changes to the ISO Tariff are needed to delay the full integration of demand**
16 **response into the wholesale markets by one year?**

17 A: Two main categories of market rule changes are needed to implement the delay – from
18 June 1, 2017 to June 1, 2018 – in the full integration of demand response into the
19 wholesale markets.

20
21 First, changes are needed to extend the currently effective rules for Real-Time Demand
22 Response Resources by one year, such that they will continue to apply through the
23 eighth Capacity Commitment Period – *i.e.*, June 1, 2017 through May 31, 2018. These

1 changes involve simply changing the operative date from June 1, 2017, to June 1, 2018
2 in the appropriate areas of the ISO Tariff.

3
4 Second, the market rules that will be applied to Demand Response Capacity Resources
5 that cleared in the eighth Forward Capacity Auction (“FCA 8”) for the eighth Capacity
6 Commitment Period – *i.e.*, the period June 1, 2017 through May 31, 2018 – must be
7 clarified. FCA 8 has already been conducted and some Demand Response Capacity
8 Resources cleared in that auction under the current set of market rules, which specifies
9 that full integration was going to be in effect as of June 1, 2017. But if full integration
10 is delayed by a year, the specific rules governing Demand Response Capacity
11 Resources for the eighth Capacity Commitment Period become unclear.

12
13 To address this issue, the instant market rule changes specify that a Demand Response
14 Capacity Resource that cleared in FCA 8 will be treated as a Real-Time Demand
15 Response Resource during the eighth Capacity Commitment Period. Further, as a
16 result of treating Demand Response Capacity Resources as Real-Time Demand
17 Response Resources, changes must be made to avoid the application of the Shortage
18 Event penalty construct to Demand Response Capacity Resources. The current penalty
19 structure in place for Real-Time Demand Response Resources will apply, and this
20 change will ensure that only one set of adjustments for non-performance is applied to
21 Demand Response Capacity Resources during the eighth Capacity Commitment Period.

1 **IV. REVISING THE METHODOLOGY USED TO DERIVE DEMAND RESPONSE**
2 **BASELINES**

3 **Q: Please summarize the changes to the Demand Response Baseline methodology.**

4 A: The ISO is replacing the current 90/10 Demand Response Baseline methodology with
5 one that is less complex to administer and that performs comparably or better as
6 quantified by accuracy, bias, and variability metrics.

7

8 The ISO is implementing a “mean 10 of 10” methodology – that is, a ten-day rolling
9 average of meter data from the ten most recent non-holiday weekdays on which the
10 demand response resource was not dispatched. To simplify baseline administration and
11 ensure that seasonal variation does not distort the results, the ISO will limit the pool of
12 historical data used in the baseline calculation to the most recent six weeks.

13

14 As of the date of the full integration of demand response, the ISO will also calculate
15 baselines for two additional day types, Saturdays and Sundays/holidays, using a “mean
16 5 of 5” methodology. The mean 5 of 5 methodology calculates a five-day rolling
17 average of meter data from the five most recent like days on which the demand
18 response resource was not dispatched. The additional day types are designed to provide
19 baselines for those day types that are more accurate than applying the baselines of non-
20 holiday weekdays to those day types.

21

22 The ISO plans to implement these changes as follows:

- 23 • beginning June 1, 2017, baselines for non-holiday weekdays will be calculated
24 using the mean 10 of 10 baseline methodology; and

- beginning June 1, 2018, baselines for Saturdays and for Sundays (including Demand Response Holidays) will be calculated using the mean 5 of 5 baseline methodology.

Q: What is a Demand Response Baseline, how is it used, and how is it currently determined?

A: A Demand Response Baseline is the expected energy consumption of a demand response asset for each interval of an Operating Day.⁹ The baseline is used to estimate the demand reduction achieved by the asset if and when the associated resource is dispatched to reduce consumption.

In 2003, the ISO developed and implemented the current 90/10 Demand Response Baseline methodology to facilitate the participation of demand response resources in the wholesale capacity and energy markets. This 90/10 baseline methodology estimates the expected energy consumption of a demand response asset by *simulating* a ten-day rolling average of meter data from the most recent days on which the associated resource was not dispatched. Under this approach, the ISO takes 90 percent of the previously calculated baseline for each five-minute interval of an Operating Day, and adds to each interval ten percent of the interval meter data from the most recent day on which the associated resource was not dispatched. While the Demand Response Baseline methodology has been revised since 2003, the basic computation algorithm has remained largely unchanged.

⁹ A Demand Response Baseline is calculated for each Demand Response Asset. One or more Demand Response Assets comprise a Demand Response Resource.

1 **Q: Why is the ISO proposing to change the Demand Response Baseline methodology**
2 **at this time?**

3 A: Simulating a ten-day rolling average using the current 90/10 baseline methodology is
4 administratively complex and overly labor- and data-intensive. Specifically, the 90/10
5 baseline methodology uses a recursive algorithm in which each new calculation of a
6 baseline relies primarily on the prior baseline, and each baseline is derived from past
7 meter data. Accordingly, if *any* past meter data is corrected within the ISO's
8 resettlement period, there will be a very significant "ripple effect" on the calculated
9 baselines from the day of the corrected data forward. That is, every time a data
10 correction is made, every subsequent baseline, starting with the baseline for the first
11 day that was computed using the corrected data, needs to be recalculated, meaning that
12 any data corrections during a resettlement period impact all future settlements. Given
13 the possibility of data corrections, the ISO and participants must store and manage
14 many months of data in order to recalculate baselines if any meter data is found to be
15 incorrect, even though the impact of any set of meter data on the calculated baseline
16 diminishes significantly over time. If data problems are found following the end of a
17 data resubmission period, unwinding the impact of the incorrect data on the settlement
18 of the demand response resource is very complex.

19
20 **Q: How did the ISO identify the new Demand Response Baseline methodologies**
21 **presented in this filing?**

22 A: The ISO analyzed alternative baseline methodologies and compared them to the ISO's
23 90/10 baseline methodology to determine which one(s) would:

- 1 • perform comparably to, or better than, the existing 90/10 baseline methodology
2 as quantified by accuracy,¹⁰ bias,¹¹ and variability¹² metrics;
- 3 • address the administrative issues with the 90/10 baseline methodology and be
4 transparent and simple to apply; and
- 5 • allow for the computation of Demand Response Baselines for three different
6 day-types (non-holiday weekday, Saturday, and Sunday/holiday) at the time of
7 full integration.

8

9 The ISO considered a range of methodologies as potential alternatives to the existing
10 90/10 baseline methodology. These alternatives varied in the following respects:

- 11 • using the statistical median in addition to the mean,
- 12 • using a weighted average where more recent days are given greater weight in
13 the baseline computation, and
- 14 • taking the average of the most recent 10 non-event weekdays with either the
15 highest or the middle daily average hourly loads.

16

17 The ISO narrowed the alternative methodologies to those that performed very similarly
18 to the current 90/10 baseline methodology with respect to accuracy, bias, and
19 variability metrics. Those methodologies were also examined for administrative
20 complexity, and for suitability for computing baselines of three different day-types.

21

22 The ISO determined that baselines based solely on meter data, rather than on (in whole
23 or in part) prior baselines, would reduce administrative complexities. Further, the ISO

¹⁰ Accuracy is a measure of how closely the estimated baseline predicts the asset's actual load.

¹¹ Bias is the systematic tendency of a baseline method to over-predict or under-predict actual load.

¹² Variability is a measure of how well the baseline predicts actual load under many different conditions (for example, time of day, day of week) and across many different customers.

1 determined that baseline approaches that limit the period for which historical meter data
2 must be retained reduce the need to store and manage many months of data and limit
3 the possibility of including data in the baseline computation that is from a prior season.
4 (Calculating a baseline using data from a different season lessens the accuracy of the
5 forecasted baseline.)

6
7 **Q: Which baseline methodology was selected for use during the period before full**
8 **integration, and what are the core attributes of that methodology?**

9 Based on the analysis described above, the ISO selected the “mean 10 of 10”
10 methodology to replace the 90/10 baseline methodology due to its transparency and
11 simplicity.

12
13 The mean 10 of 10 methodology is an actual (not simulated) ten-day rolling average of
14 meter data from the ten most recent days (of the same day type) on which the demand
15 response resource was not dispatched. For non-holiday weekdays, the pool of historical
16 data used in the baseline computations is limited to the most recent 30 non-holiday
17 weekdays, which corresponds to limiting the historical data used in the baseline
18 computations to six weeks.

19
20 To determine the Demand Response Baseline for a non-holiday weekday, the mean 10
21 of 10 methodology computes the mean in each interval using meter data from ten non-
22 holiday weekdays chosen from the ten most recent non-holiday weekdays on which the
23 resource was not dispatched from the prior six weeks. Where there are fewer than ten

1 non-holiday weekdays on which the resource was not dispatched within the prior six
2 weeks, the most recent non-holiday weekday(s) on which the resource was dispatched
3 will be included until ten non-holiday weekdays are identified for use in the baseline
4 calculation.

5
6 **Q: Please summarize the high-level benefits of the mean 10 of 10 methodology.**

7 A: In addition to performing comparably to the 90/10 baseline methodology in terms of
8 accuracy, bias, and variability, the mean 10 of 10 methodology is more transparent and
9 addresses the administrative burden associated with the current 90/10 baseline
10 methodology.

11
12 The mean 10 of 10 methodology calculates the current-day baseline using only meter
13 data and does not rely in any part on previously calculated baselines. This change
14 addresses the administrative issues caused by the recursive nature of the 90/10 baseline
15 methodology. As a result, any changes to previously calculated baselines – for
16 example, due to corrected meter data – will not impact subsequent baselines. Limiting
17 the data used in the calculation to a six-week historical period: (1) reduces the need to
18 store and manage many months of data in order to recalculate a baseline, should that
19 prove necessary; and (2) ensures that baselines are calculated using contemporary data
20 rather than historical data (possibly from a different season), which provides a more
21 accurate forecast of expected consumption patterns for the current Operating Day.

22

1 **Q: How will Demand Response Baselines for Saturdays and Sundays/holidays be**
2 **determined upon full integration of demand response (if that occurs) on June 1,**
3 **2018?**

4 A: It is not possible to use ten days of meter data to calculate the baseline for Saturdays,
5 and for Sundays/holidays, while still limiting the historical data used in the calculation
6 to a six-week period. In a six-week period with no holidays, there are only six
7 Saturdays and six Sundays. As mentioned earlier, increasing the historical period
8 beyond six weeks is problematic due to seasonal variation in consumption patterns and
9 increased administrative complexity. For this reason, the use of the mean 10 of 10
10 methodology would not be appropriate for the Saturdays and Sundays/holidays day
11 types.

12
13 While as a general matter the use of more days in the baseline calculation creates a
14 more accurate picture of typical load, the ISO's analysis indicates that it is appropriate
15 to use a five-day rolling average (mean 5 of 5) methodology for the Saturday and
16 Sunday/holiday day types. This methodology computes the mean in each interval using
17 five days of meter data from the five most recent Saturdays or Sundays/holidays on
18 which the demand response resource was not dispatched from the prior six weeks.
19 Where there are less than five Saturdays or Sundays/holidays on which the demand
20 response resource was not dispatched in the prior six weeks, the most recent day(s) of
21 the same day type on which the demand response resource was dispatched will be
22 included until five days are identified for use in the baseline calculation.

23

1 In determining how many days to use in the baseline calculation for Saturdays and
2 Sundays/holidays, the ISO considered the historical frequency of operating reserve
3 deficiencies on these day types to estimate the frequency with which scarcity conditions
4 might occur starting with the 2018-2019 Capacity Commitment Period, when baselines
5 for Saturdays and Sundays/holidays are first estimated. The frequency of scarcity
6 conditions becomes relevant starting with the 2018-2019 Capacity Commitment Period
7 because the two-settlement capacity market design (“Pay For Performance”) goes into
8 effect at that time. Under Pay For Performance, resources with Capacity Supply
9 Obligations, including Demand Response Capacity Resources, must provide energy or
10 reserves during scarcity conditions to reduce the possibility of a negative Capacity
11 Performance Payment.

12
13 Historical data indicate that scarcity conditions rarely occur on Saturdays and
14 Sundays/holidays. Indeed, since the FCM was implemented on June 1, 2010, *all* six-
15 week periods have had at least five Saturdays or Sundays/holidays on which scarcity
16 conditions did *not* occur. This means that it is highly likely that a baseline calculated as
17 the average of five days of meter data would not affect the settlement of demand
18 response resources responding to scarcity conditions on Saturdays or Sundays/holidays.
19 Furthermore, the ISO’s analysis suggests that a baseline using five days of data is not
20 substantially less accurate than a baseline computed using six days of data.

1 **Q: Please summarize the ISO Tariff changes needed to implement the changes to the**
2 **Demand Response Baseline methodology.**

3 A: The market rule changes needed to effectuate the revised baseline methodology
4 include:

- 5 • Changes to Section III.8A of the ISO Tariff to incorporate the mean 10 of 10
6 methodology prior to full integration; and
7
- 8 • Changes to Section III.8B of the ISO Tariff to incorporate the mean 10 of 10 and
9 mean 5 of 5 methodologies at the time of full integration.

10
11 Given the resources needed to implement the baseline changes, the fastest that the ISO
12 would be able to implement the mean 10 of 10 methodology is June 1, 2017 (a year
13 prior to full integration). Until then, the ISO would continue using the current 90/10
14 baseline methodology. At the time of full integration (being changed here to June 1,
15 2018), the ISO would begin using the mean 5 of 5 methodology for Saturdays and
16 Sundays/holidays.

17

18 **V. MODIFYING THE SIMULTANEOUS AUDITING REQUIREMENT OF REAL-**
19 **TIME DEMAND RESPONSE AND REAL-TIME EMERGENCY**
20 **GENERATION RESOURCES**

21 **Q: Please provide an overview of the ISO Tariff’s auditing requirement for demand**
22 **resources, and its purpose.**

23 A: Real-Time Demand Response (“RTDR”) and Real-Time Emergency Generation
24 (“RTEG”) Resources¹³ are audited each season to establish their capability for
25 providing capacity to the electric system in that season. During an audit, the resource is

¹³ An RTDR or RTEG *Resource* is generally an aggregation of RTDR or RTEG *Assets*, respectively, located in the same Dispatch Zone. An RTDR Asset is generally a single end-use facility. An RTEG Asset is an emergency generator located behind the Retail Delivery Point of a single end-use facility.

1 sent a Dispatch Instruction and the resource's performance in response to that
2 instruction is measured,¹⁴ which is used to establish the resource's Demand Reduction
3 Value. These audits serve various purposes including establishing the resource's
4 capability for operational planning, determining whether the resource has achieved
5 commercial operation (which affects the refunding of any Financial Assurance
6 collected from the resource's Market Participant), and determining settlement in
7 seasons when the resource was not dispatched in response to an actual capacity
8 deficiency event. Where an RTDR Asset and an RTEG Asset are located at the same
9 facility, the current rules require that they be audited simultaneously to prevent over-
10 crediting the combined capacity of the assets.

11
12 **Q: Please summarize the changes to the simultaneous auditing of Real-Time Demand**
13 **Response and Real-Time Emergency Generation Resources.**

14 A: The ISO is proposing changes to the simultaneous auditing rules for RTDR and RTEG
15 Resources¹⁵ to reduce the burden of having to dispatch all RTDR Assets that are
16 included in a RTDR Resource but are not co-located with an RTEG Asset an additional
17 time during a season in order to establish audit values for a few co-located RTDR and
18 RTEG Assets. In short, the current rules can require the dispatch of far more assets
19 than necessary to establish the needed audit values. Under the new approach, Market

¹⁴ The performance of an RTDR or RTEG Asset is measured by comparing the metered demand of the asset during the period of dispatch to its adjusted Demand Response Baseline. The performance of an RTDR or RTEG Resource is the sum of the performances of its constituent assets.

¹⁵ A single end-use facility with an emergency generator could participate in the wholesale market as an RTDR Asset and as an RTEG Asset.

1 Participants with RTDR and RTEG Resources will have the option to audit their RTEG
2 Resources by simultaneously dispatching *only the co-located RTDR Assets* at the time
3 of the RTEG Resource audit. Alternatively, Market Participants may continue to audit
4 their RTEG Resources by simultaneously dispatching the entire RTDR Resource
5 associated with co-located RTDR and RTEG Assets, as under the current rules. The
6 ISO plans to implement the new simultaneous auditing rules on June 1, 2016.

7
8 **Q: What is the purpose behind the simultaneous auditing requirement?**

9 A: As mentioned above, the simultaneous audit requirement is intended to prevent over-
10 crediting the combined capacity of RTDR Assets and RTEG Assets located at the same
11 facility. For example, assume a facility with 500 kW of baseline energy consumption and a
12 300 kW emergency generator. If this facility participates as an RTDR Asset, it may be able
13 to interrupt 300 kW of consumption in response to a dispatch instruction, resulting in a 300
14 kW demand reduction value. If the RTEG Asset at the same facility is audited at a separate
15 time, its dispatch (assuming that it performs at its full capacity) would result in a 300 kW
16 demand reduction value. The sum of the two demand reduction values is 600 kW.
17 However, the demand reduction value of this facility should not exceed 500 kW (its baseline
18 energy consumption) if this facility is not capable of Net Supply.¹⁶ This example shows that
19 allowing such facilities to audit the RTEG Asset separately from the RTDR Asset could
20 over-credit the total capacity of the facility. Requiring the RTEG Asset and the RTDR
21 Asset to be audited simultaneously ensures that the facility's demand reduction value is
22 limited to 500 kW.

¹⁶ The ISO Tariff defines Net Supply as energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation. Most facilities with emergency generators are not capable of Net Supply.

1 **Q: What aspect of the simultaneous auditing requirement is the ISO changing and**
2 **why?**

3 A: Where an RTDR Asset and RTEG Asset are co-located at an end-use facility, the current
4 ISO Tariff provisions require that the entire RTDR Resource – *which may include RTDR*
5 *Assets at other locations* – be audited simultaneously with an audit of the RTEG Resource.
6 This requirement can lead to significant inefficiency, however, because RTDR Resources
7 are more likely than RTEG Resources to be dispatched in the normal course of a season.
8 (This is because RTDR Resources are dispatched in response to OP-4, Action 2,¹⁷ whereas
9 RTEG Resources are dispatched in response to the less frequent OP-4, Action 6.¹⁸) It is
10 more common that the Capacity Value of an RTDR Resource is established in response to
11 an OP-4 event in a season, but the Capacity Value of an associated RTEG Resource is not.
12 The current simultaneous audit requirement necessitates that the entire RTDR Resource,
13 which may have already been dispatched in response to OP-4, be dispatched once again in
14 the same season, even if there is only one facility with a co-located RTDR and RTEG Asset.
15
16 The burden of having to audit the entire RTDR Resource at the time of the RTEG Resource
17 audit can be reduced by allowing Market Participants to audit their RTEG Resources by
18 simultaneously dispatching *only the co-located RTDR Assets* if the RTDR Resource has

¹⁷ ISO New England Operating Procedure No. 4, (“OP-4”) establishes the criteria and actions to be taken during capacity deficiencies. See http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isono/op4/op4_rto_final.pdf.

¹⁸ This action was last called in year 2006. OP-4, Action 6 allows the ISO to implement a voltage reduction of 5% of normal operating voltage (requiring more than 10 minutes to attain) and to dispatch RTEG resources in the amount and location required. The last major revision of OP-4 took effect in June 2010 with the implementation of the Forward Capacity Market. At that time, OP-4 was consolidated into 11 actions (from 16 actions). What is now known as OP-4, Action 6 was called OP-4, Action 12 in year 2006.

1 already established a Seasonal DR Audit value by performing in response to OP-4 dispatch.
2 This approach preserves the intent of the simultaneous auditing requirement – *i.e.*, to prevent
3 the over-crediting of the capacity of RTDR Assets and RTEG Assets located at the same
4 facility – but eliminates the needless re-auditing of the remainder of the RTDR Resource.
5 Market Participants will still be able to audit their RTEG Resources by simultaneously
6 dispatching the entire RTDR Resource associated with co-located RTDR and RTEG Assets
7 if they so choose.

8
9 **Q: In the unlikely event of a simultaneous dispatch of both RTDR and RTEG**
10 **Resources in response to OP-4 in a season, can Market Participants use the**
11 **performance of these resources during the simultaneous dispatch to establish**
12 **audit values?**

13 A: Yes. Market rule changes will allow participants to use a coincident OP-4 activation of
14 RTDR and RTEG Resources with co-located assets to establish Seasonal DR Audit values
15 for each resource. Because a coincident dispatch of RTDR and RTEG Resources with co-
16 located assets satisfies the simultaneous audit requirement, provided that the dispatch of
17 both resources is of sufficient duration, it is appropriate to allow a concurrent dispatch of
18 RTDR and RTEG Resources to establish audit values.

19
20 **Q: In what sections of the ISO Tariff are changes required in order to effectuate the**
21 **revisions to the simultaneous auditing requirement?**

22 A: All of the changes to the ISO Tariff needed to effectuate the revisions to the
23 simultaneous auditing requirement are contained in Section III.13.6.1.5.4.

1 **Q: Does this conclude your testimony?**

2 A: Yes.

3

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

5

6 Executed on October 28, 2015

7

8



9 Henry Y. Yoshimura

New England Governors, State Utility Regulators and Related Agencies*

Connecticut

The Honorable Dannel P. Malloy
Office of the Governor
State Capitol
210 Capitol Ave.
Hartford, CT 06106
Liz.Donohue@ct.gov
Paul.Mounds@ct.gov

Connecticut Public Utilities Regulatory
Authority
10 Franklin Square
New Britain, CT 06051-2605
robert.luysterborghs@ct.gov
michael.coyle@ct.gov
clare.kindall@ct.gov

Maine

The Honorable Paul LePage
One State House Station
Office of the Governor
Augusta, ME 04333-0001
Kathleen.Newman@maine.gov

Maine Public Utilities Commission
18 State House Station
Augusta, ME 04333-0018
Maine.puc@maine.gov

Massachusetts

The Honorable Charles Baker
Office of the Governor
State House
Boston, MA 02133

Massachusetts Attorney General Office
One Ashburton Place
Boston, MA 02108
rebecca.tepper@state.ma.us

Massachusetts Department of Public Utilities
One South Station
Boston, MA 02110
Nancy.Stevens@state.ma.us
morgane.treanton@state.ma.us

New Hampshire

The Honorable Maggie Hassan
Office of the Governor
26 Capital Street
Concord NH 03301
kerry.mchugh@nh.gov
Meredith.Hatfield@nh.gov

New Hampshire Public Utilities Commission
21 South Fruit Street, Ste. 10
Concord, NH 03301-2429
tom.frantz@puc.nh.gov
george.mccluskey@puc.nh.gov
F.Ross@puc.nh.gov
David.goyette@puc.nh.gov
RegionalEnergy@puc.nh.gov
Robert.scott@puc.nh.gov

Rhode Island

The Honorable Gina Raimondo
Office of the Governor
82 Smith Street
Providence, RI 02903
eric.beane@governor.ri.gov
todd.bianco@puc.ri.gov
Marion.Gold@energy.ri.gov
christopher.kearns@energy.ri.gov
Danny.Musher@energy.ri.gov
nicholas.ucci@energy.ri.gov

Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888
Margaret.curran@puc.ri.gov
paul.roberty@puc.ri.gov
todd.bianco@puc.ri.gov

Vermont

New England Governors, State Utility Regulators and Related Agencies*

The Honorable Peter Shumlin
Office of the Governor
109 State Street, Pavilion
Montpelier, VT 05609
Darren.Springer@state.vt.us
Justin.johnson@state.vt.us

Vermont Public Service Board
112 State Street
Montpelier, VT 05620-2701
mary-jo.krolewski@state.vt.us
sarah.d.hofmann@state.vt.us

Vermont Department of Public Service
112 State Street, Drawer 20
Montpelier, VT 05620-2601
bill.jordan@state.vt.us
chris.recchia@state.vt.us
Ed.McNamara@state.vt.us

New England Governors, Utility Regulatory and Related Agencies

Anne Stubbs
Coalition of Northeastern Governors
400 North Capitol Street, NW
Washington, DC 20001
coneg@sso.org

Heather Hunt, Executive Director
New England States Committee on Electricity
655 Longmeadow Street
Longmeadow, MA 01106
HeatherHunt@nescoe.com
JasonMarshall@nescoe.com

Rachel Goldwasser, Executive Director
New England Conference of Public Utilities
Commissioners
Concord, NH 03301
rgoldwasser@necpuc.org

Margaret “Meg” Curran, President

New England Conference of Public Utilities
Commissioners
89 Jefferson Boulevard
Warwick, RI 02888
margaret.curran@puc.ri.gov

Harvey L. Reiter, Esq.
Counsel for New England Conference of Public
Utilities Commissioners, Inc.
c/o Stinson Morrison Hecker LLP
1150 18th Street, N.W., Ste. 800
Washington, DC 20036-3816
HReiter@stinson.com