April 15, 2016

BY ELECTRONIC FILING

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

RE: **ISO New England Inc. and New England Power Pool Participants Committee, Docket No. ER16-____-000, Demand Curve Design Improvements**

Dear Secretary Bose:

In response to the order issued by the Commission on December 28, 2015 in Docket Nos. EL16-15-000 and ER14-1639-000,[1] ISO New England Inc. (the "ISO") and the New England Power Pool ("NEPOOL") Participants Committee (together, the "Filing Parties"),[2] hereby electronically submit this transmittal letter and revisions to the ISO Tariff [3] to provide for the inclusion of sloped zonal demand curves in the Forward Capacity Market rules beginning with the Forward Capacity Auction to be held in February 2017 ("FCA 11"). The package of rule changes submitted in this filing is referred to hereafter as the "Demand Curve Design Improvements."

I. EXECUTIVE SUMMARY

In the Forward Capacity Market, demand curves are used to determine how much capacity to procure to address the resource adequacy objectives of the New England region. The

[1] *ISO New England Inc., et al., Order Instituting Section 206 Proceeding*, 153 FERC ¶ 61,338 (2015) (the "December 28 Order").

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

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

market uses a set of demand curves for the system as a whole and for constrained zones[4] in order to reflect the physical limits of the transmission system to deliver energy between different sub-regions. As discussed in the remainder of this filing, the Demand Curve Design Improvements are a major improvement in the way that demand is currently represented in the Forward Capacity Market.

Under the current market design, the system and zonal demand curves are relatively simplistic. The current system-wide demand curve is linear with a constant downward slope. However, this straight-line shape is not a function of any specific design principle (such as reflecting the reliability impact of adding incremental system capacity). The constrained zone demand "curves" are more rudimentary than the system-wide curve in that they are fixed requirements (vertical lines) that reflect the determinative outcome of engineering analysis of how much energy can be reliably delivered into or out of the zone. This current set of demand curves has significant limitations from an economic and reliability standpoint, including, as the Commission recognized in the December 28 Order, sub-optimal performance in terms of price volatility and market power protection at the zonal level.

The Demand Curve Design Improvements address the shortcomings of the existing set of demand curves and will significantly improve the performance of the Forward Capacity Market in a number of ways. The new set of curves (at both the system and zonal level) are based on design principles that reflect the marginal improvement in reliability associated with adding capacity in constrained capacity zones versus the remainder of the system. The resulting set of system and zonal demand curves tend to be downward sloping and convex.

The new set of demand curves will significantly improve the performance of the Forward Capacity Market because they will set prices that more accurately reflect the locational marginal reliability impact of capacity. To do so, the Demand Curve Design Improvements will calculate prices for each zone that are proportional to the marginal reliability impact values at each capacity level. This design ensures that the amount of capacity that is cleared at the system and zonal levels is cost-effective, as outlined Sections IV and VI of the Geissler-White Testimony. Significantly, resources in a constrained zone must compete with a broader set of resources including those located outside the zone because the new set of curves account for the partial substitutability of resources in different zones (Section VII of the Geissler-White Testimony explains how the Demand Curve Design Improvements allow for partial substitutability in clearing, and why this increases competition in more detail).

At the zonal level, replacing the existing vertical demand curves with sloped demand curves addresses the price volatility and market power concerns raised by the Commission in the December 28 Order by specifying a more gradual change in prices corresponding to shifts in supply and accounting for the partial substitutability of capacity across zones. By addressing the

[4] Historically, constrained zones in New England have included sub-regions which have limits on the amount of energy that can be reliably delivered outside the region (export-constrained zones) and sub-regions which have limits on the amount of energy that can be reliably delivered into the region (import-constrained zones).

market power concerns associated with the existing zonal demand curves, the existing administrative pricing rules for import-constrained zones can now be eliminated. Importantly, the Demand Curve Design Improvements also resolve the ISO's concerns with prior design efforts, by specifying a methodology that is robust and expected to perform well under a range of potential future system and market conditions, including different zonal configurations.

As already noted, the Demand Curve Design Improvements include a new System-Wide Capacity Demand Curve. As discussed further in this filing letter and in the accompanying testimony, the adoption of a new system-wide demand curve that is based on the reliability impact of adding incremental capacity is necessary to ensure that capacity is procured in a cost-effective manner across all zones. The ISO has concluded that any system demand curve that is not developed using a framework based on the marginal reliability impact of capacity, including the existing linear system curve, will not procure capacity in a cost-effective manner.[5]

As discussed in Section IV.I of this filing letter, the new system-wide demand curve is phased in over a period of time in order to smooth the transition from the existing system-wide curve to the new system-wide curve. In order to address the potential negative impact on investor confidence that could be associated with a relatively abrupt new system curve design, the Demand Curve Design Improvements include a transition period of up to three years that will provide a more gradual move to the new system curve.

The Demand Curve Design Improvements and their benefits are summarized in Section IV of this filing letter. In support of the changes, the ISO also is submitting testimony from several expert witnesses. In support of the overall design of the demand curves from an economic perspective, the ISO is submitting the joint testimony of Christopher Geissler, Economist, and Matthew White, Chief Economist (the "Geissler-White Testimony"). In addition, the ISO is submitting testimony from Alan McBride, Director, Transmission Strategy and Services, (the "McBride Testimony") to explain, from a power system engineering standpoint, how transfer capability between constrained capacity zones and the rest of the system is treated under the Demand Curve Design Improvements. All of the testimony is sponsored solely by the ISO.

The Demand Curve Design Improvements are supported by most stakeholders in New England. As discussed in Section VI of this filing letter, the NEPOOL Participants Committee voted to support the Demand Curve Design Improvements by a Vote of 75.94% in favor. NEPOOL's support included representatives of both suppliers and consumers. The New England States Committee on Electricity, representing the collective position of the six states in regional electricity matters, also has indicated its support for the Demand Curve Design Improvements.

[5] Section VI of the Geissler-White Testimony explains the criteria the ISO uses to evaluate whether demand curves are cost-effective.

II. REQUESTED EFFECTIVE DATE

The Filing Parties request that the Demand Curve Design Improvements become effective on June 15, 2016 (61 days after filing). The implementation of the Demand Curve Design Improvements on the requested effective date means that the new rules will be applicable during the early stages of the FCA 11 auction process, including the annual process for reviewing and developing the specific system-wide and zonal demand curves to be used when FCA 11 is administered in February 2017.

III. 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 Tariff and the Transmission Operating Agreement with the New England Participating Transmission Owners. In its capacity as an RTO, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

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 service under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, demand resource providers, developers and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission,[6] the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, "NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff."

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

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IV. EXPLANATION OF THE DEMAND CURVE DESIGN IMPROVEMENTS

A. The Demand Curve Design Improvements Adopt a New Approach to Representing Demand in the Forward Capacity Market that is a Major Improvement on the Existing Design

The key innovation of the Demand Curve Design Improvements is the adoption of a new approach to representing demand in the capacity market that is based on the relative improvement in reliability associated with adding an increment of capacity at a particular location. The new approach relies on engineering analysis to determine the marginal improvement in reliability associated with incremental capacity at the system and zonal levels. As discussed below and in more detail in the Geissler-White Testimony, adopting system and zonal demand curves that are based on the marginal reliability improvement associated with incremental capacity at a particular location is consistent with sound economic principles and will enable the Forward Capacity Market to procure capacity more cost-effectively than today.

The new approach to representing demand in the capacity market is fundamentally different than the approach used to develop the linear (straight line) slope of the existing System-Wide Capacity Demand Curve. The approach used to develop the existing system demand curve involved evaluating a range of possible linear demand curves and using simplified market models to assess the expected performance of these candidate curves from a number of perspectives (including price volatility, reliability and market power). Initially, the same approach that was used to develop the linear system demand curve also was used in the effort to develop sloped zonal demand curves. However, the ISO determined that this approach failed to

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

produce satisfactory results. The ISO concluded that additional time and a more rigorous engineering-economic approach would be required in order to develop an overall demand curve design that would satisfy market efficiency and pricing objectives, provide reasonable market power protections and be sufficiently robust to perform well across a range of potential zonal configurations and market conditions that could occur in future Forward Capacity Auctions. The ISO discussed these issues in more detail in a report that it submitted to the Commission on May 18, 2015 in Docket No. ER14-1639.

While the earlier approach would have produced a relatively static set of linear demand curves, the new design approach uses a more dynamic, engineering-based methodology that is applied each year to produce a set of demand curves tailored to the specific zonal configuration of each Forward Capacity Auction. While the set of demand curves produced for each auction is likely to be quite stable from year to year, the curves produced by the new methodology will be updated annually to reflect changing conditions. The methodology uses the ISO's full-scale reliability planning simulation system (known as Multi-Area Reliability Simulation, or "MARS") to develop a set of demand curves that directly reflect the reliability impact of adding additional capacity in each Capacity Zone. As discussed in depth in Section VIII of the Geissler-White Testimony, the demand curves produced by this methodology are expected to perform well in different system conditions and across a range of possible future zonal configurations.

The new methodology uses engineering data produced by MARS to determine the reliability impact associated with adding capacity at a particular location.[8] Among other things, MARS calculates a performance metric known as "expected energy not served" (or "EENS"). EENS is measured in MWh per year and is calculated after considering the amount of capacity installed on the system and in each constrained zone. For purposes of developing an appropriate set of demand curves for each auction, the EENS data produced by MARS is used to calculate demand curves that reflect the expected improvement in reliability associated with adding incremental capacity at a particular location. In the market rules, the variable measuring this expected improvement in reliability is referred to as the Marginal Reliability Impact (or "MRI") of capacity.

As illustrated conceptually in Figure 1 below, the slope of a curve that shows MRI values as a function of capacity is steeply sloped at lower capacity quantities (when adding capacity would be expected to result in a bigger improvement in reliability). The MRI values are closer to zero and the function flatter at higher capacity quantities (when adding capacity would be expected to produce smaller improvements in reliability). In other words, as additional capacity is added to the system (or to any zone), it has a progressively diminishing marginal reliability impact. The new sloped demand curves will accurately reflect this fundamental engineering attribute of how capacity affects system reliability.

[8] MARS is the same simulation system that already is used to help develop the Installed Capacity Requirement and other values that specify how much capacity is required for resource adequacy purposes from a system planning perspective.

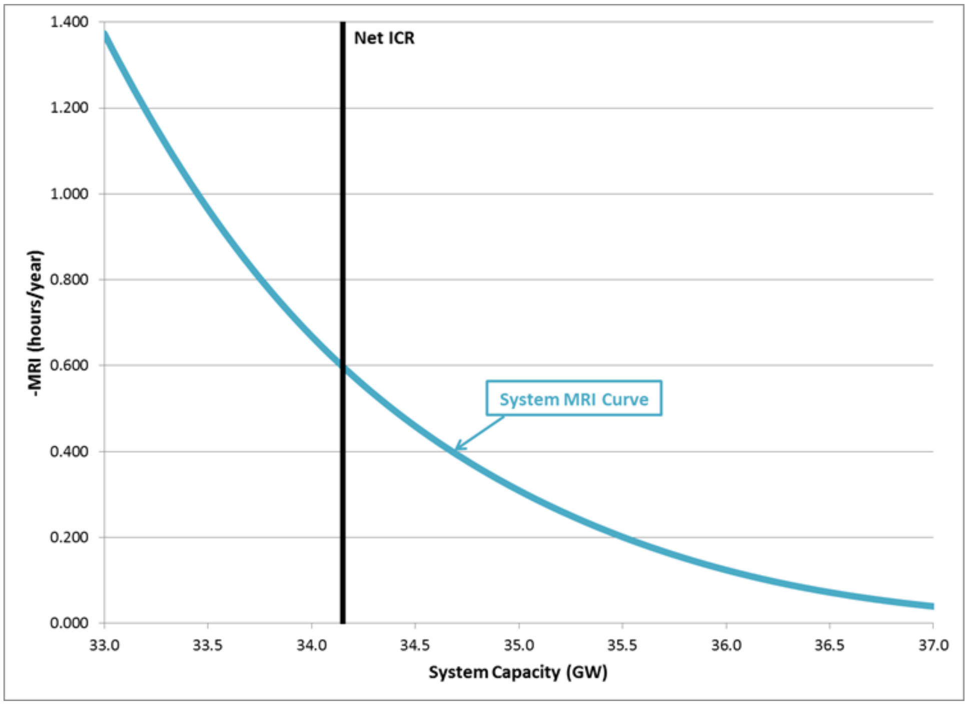

Figure 1

For export-constrained capacity zones, the MRI methodology is the same but it produces a different curve shape because the reliability impact of adding capacity in an export-constrained zone rather than in the Rest-of-Pool Capacity Zone is different. In simple terms, the reliability impact of transferring capacity from the Rest-of-Pool Capacity Zone to an export-constrained zone tends to worsen system reliability, resulting in an MRI curve for an export-constrained zone that gets progressively steeper as higher levels of capacity are procured in the zone. How the MRI methodology is used to define zonal demand curves for export-constrained zones is discussed in more detail in Section IV.F of this filing letter.

B. The MRI Functions Are Converted into Priced Demand Curves that Satisfy the Reliability and Sustainability Design Principles

As explained in the Geissler-White Testimony, the MRI-based demand curves must be calibrated to satisfy two key design principles: reliability and sustainability. The reliability principle requires that the market be designed to procure sufficient capacity to meet the 1-day-in-10 Loss of Load Expectation ("LOLE") planning standard. The sustainability principle requires that the market be designed so that the average clearing price over the long term is sufficient to attract new entry when needed (for market design purposes, this clearing price is represented by the estimated cost of new entry, *i.e.* Net CONE).

In order to satisfy these two principles, a "scaling factor" is applied to the MRI-based demand curves. As discussed in Section V of the Geissler-White Testimony, the scaling factor is a derived value that is defined as the lowest value at which a demand curve will satisfy the system planning reliability criteria and pay the expected cost of new entry (in other words, the scaling factor is equal to the value which produces a system demand curve that specifies a price of Net CONE at the Net ICR[9] capacity level). Figure 2 depicts in visual form how the scaling factor is applied to an MRI-based demand curve at the system level to achieve the reliability and sustainability principles.

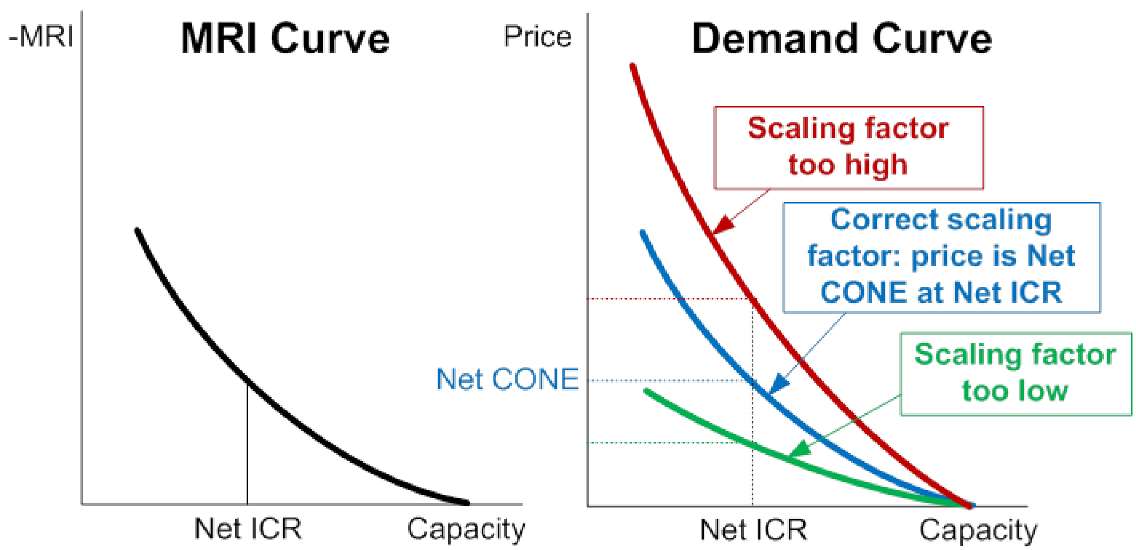

Figure 2

In broad terms, while MRI values are used to determine the shape of a demand curve, the scaling factor is used to determine the absolute prices. Using the scaling factor to calibrate the MRI-based demand curves ensures that the system demand curve specifies a price of Net CONE at the Net ICR capacity quantity, which is expected to cause the MRI-based demand curves to perform well from both reliability and sustainability perspectives.[10]

C. MRI-Based Demand Curves Have Significant Economic Advantages

From a market design perspective, the most significant advantage of using MRI-based demand curves is the ability to use these types of curves to better optimize the clearing of capacity at the system and zonal levels on an economic basis. Sections IV and VI of the Geissler-White Testimony speak of these economic improvements in terms of satisfying the "cost-effectiveness" design principle. As explained in the testimony, capacity market demand curves are cost-effective if they allow for the optimization of the capacity market clearing

[9] For purposes of this filing, the term "Net ICR" is used to refer to the Installed Capacity Requirement (net of HQICCs).

[10] The performance of the MRI-based demand curves is discussed in detail in Section VIII of the Geissler-White Testimony.

process such that the reliability level that is achieved comes at the minimum possible cost. MRI-based demand curves are cost-effective because they allow all potential capacity resources to be evaluated based on their marginal contribution to improving system reliability and their bid cost. The ability to evaluate resources in this manner allows for the efficient allocation of capacity purchases among zones (including the Rest-of-Pool Capacity Zone) such that the system's overall reliability requirements are met at least cost. In contrast, as explained in Section VI of the Geissler-White Testimony, the ISO has concluded that the existing set of demand curves or other curves that are not based on MRI values should not be considered cost-effective. Specifically, any set of demand curves that are not based on MRI values cannot achieve the same system reliability at lower bid cost.

The ability to evaluate and compare all resources, wherever they are located, based on their marginal contribution to reliability, means that it is possible for a resource in one zone to substitute for a resource in another zone when it is cost-effective to do so and still achieve a reliable outcome. In other words, this "substitutability" feature of using the MRI-based approach means that resources in a zone compete not just against other resources in the same zone, but also against all other resources. For example, there may be cases in which, rather than clearing an expensive resource in an import-constrained zone, the MRI-based approach would clear two relatively inexpensive resources in the Rest-of-Pool Capacity Zone because each clearing outcome would produce the same overall reliability, but it would be less costly to procure the two relatively inexpensive resources in the Rest-of-Pool Capacity Zone. Section VII of the Geissler-White Testimony provides a more detailed explanation of how substitution works.

The substitutability feature of the MRI-based approach has several advantages from an economic standpoint. First, as noted above, substitutability improves auction competitiveness because resources in a constrained zone now must compete against all other resources, not just resources located in the same zone. The improved competitiveness associated with substitutability is one of the reasons that the existing administrative pricing rules can be removed as discussed in Section IV.J of this filing letter. Second, as discussed in Section VII of the Geissler-White Testimony, substitutability also improves the performance of the market from price volatility and reliability perspectives.

D. MRI-Based Demand Curves Address Price Volatility and Market Power Concerns in Import-Constrained Capacity Zones

As the Commission noted in the December 28 Order, the use of vertical demand curves for constrained zones raises concerns regarding "price volatility and a susceptibility to the exercise of market power."[11] The Demand Curve Design Changes address these concerns by replacing the existing vertical demand curves that are used for constrained zones with sloped zonal demand curves based on the new MRI-based methodology.

[11] December 28 Order at P 11.

As discussed earlier, the MRI methodology produces demand curves for the system and for import-constrained zones that are more steeply sloped at lower capacity quantities and relatively flat at higher capacity quantities. The MRI-based curves are more steeply sloped at lower capacity quantities because adding an increment of capacity produces a relatively large reduction in EENS when capacity is short. Conversely, the MRI-based curves are flatter at higher capacity quantities because adding an increment of capacity produces a relatively small reduction in EENS when capacity is long. Consistent with these properties an import-constrained zonal demand curve produced by the MRI methodology is downward sloping and slightly convex. Figure 3 shows a representation of an MRI-based demand curve for an import-constrained zone.

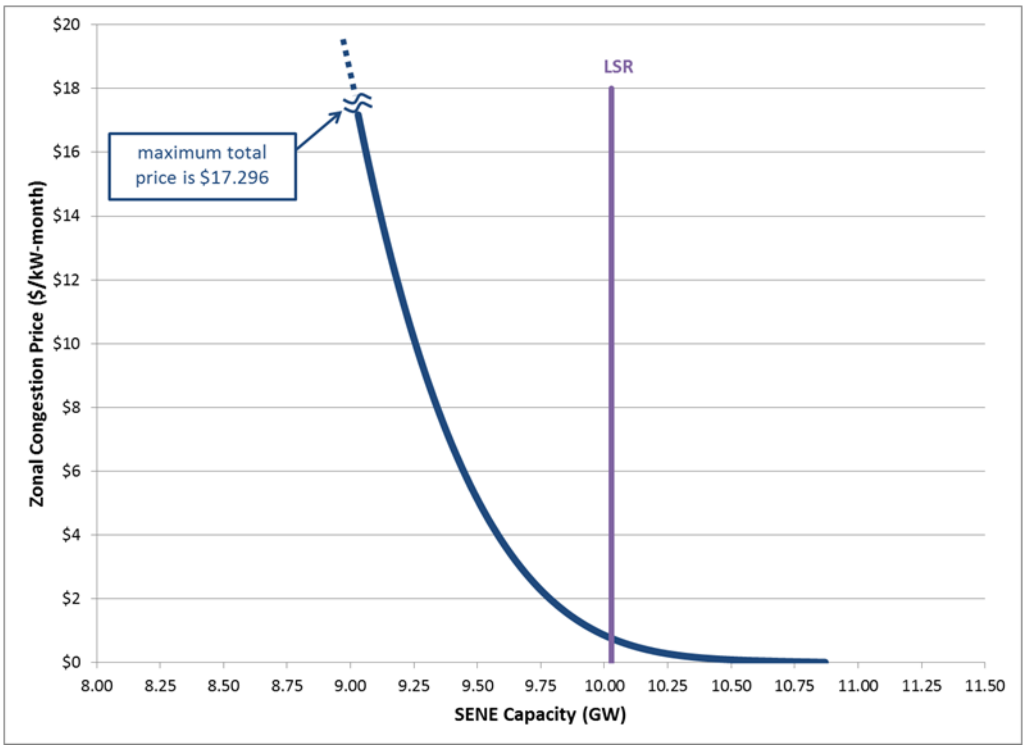

Figure 3

As discussed in Section V of the Geissler-White Testimony, it is important to understand that the zonal demand curves specify congestion prices. In an import-constrained zone, the prices specified by the zonal demand curve represent the additional amount (or congestion price) that should be paid for capacity in the zone in addition to the system clearing price. The amount of the congestion price is based on the incremental change in reliability (as measured by EENS) associated with transferring an increment (1 MW) of capacity from the Rest-of-Pool Capacity Zone into the import-constrained capacity zone.

E. The New Zonal Demand Curve Design for Import-Constrained Zones Requires an Updated Method of Identifying the Transfer Capability across Zonal Interfaces

As explained in the Section III.A of the McBride Testimony, under the current FCM structure, the amount of capacity that must be located in an import-constrained capacity zone is a fixed value that is known as the Local Sourcing Requirement. The Local Sourcing Requirement is set at the higher of two different methods of assessing the import-constrained zone's needs from a reliability perspective: (1) the Local Resource Adequacy Requirement ("LRA"), and; (2) the Transmission Security Analysis Requirement ("TSA"). In the existing market structure, the Local Sourcing Requirement is the vertical demand curve that is used in the Forward Capacity Auction for an import-constrained zone.

With the Demand Curve Design Improvements, the FCM is moving from a design that uses a single-valued capacity requirement for import-constrained zones to a design in which there is a variable capacity requirement for an import-constrained zone. The new variable requirement is specified by the zonal demand curve and depends on price. As explained in Section V of the Geissler-White Testimony, the new sloped demand curves reflect the Marginal Reliability Impact of adding incremental capacity in different locations. For constrained zones, the calculation of the MRI values is also dependent on the transfer capability across zonal interfaces. As explained in the McBride Testimony, it is important that the transfer capabilities for import-constrained zones continue to reflect certain underlying reliability assessments (*e.g.*, the various N-1, N-1-1 Line-Gen, and N-1-1 Line-Line contingency scenarios) that are currently reflected in the calculation of the LRA and TSA. However, because the LRA and TSA are fixed requirements methods, neither – if applied directly – are fully compatible with the variable requirement specified by a sloped demand curve. Nonetheless, as explained in detail in the McBride Testimony, the logic of the existing LRA and TSA methods can be readily adapted to determine a transfer capability that is appropriate for use with sloped demand curves for import-constrained zones.

At a high level, a key consideration in adapting the logic of the existing LRA and TSA methods is the different transfer capability assumptions that are used for the LRA and TSA assessments. LRA values are determined based on the assumption that transfer capability for the zone is impacted by the loss of one relevant element (a single contingency or N-1 condition). TSA values are determined based on the assumption that transfer capability is impacted by the loss of two elements (second contingency or N-1-1 conditions). As noted earlier, the Local Sourcing Requirement is defined as the "higher of" the LRA and TSA values for purposes of setting the fixed zonal requirements for import-constrained zones under the existing FCM structure.

Under the Demand Curve Design Improvements, the LRA and TSA values continue to both play a role in defining the MRI-based curves. Initially, the N-1 transfer capability that is currently used in determining the LRA is applied to the zonal MRI calculation. However, if TSA exceeds LRA, then the transfer capability that is used to define the MRI-based zonal curve is based on a *lower* value (recalling that a lower transfer capability results in a higher local capacity requirement under either the LRA or TSA assessments).[12] This new method of identifying the transfer capability to be used to calculate the MRI-based zonal curve for import-constrained zones has a similar effect as the "higher of" LRA/TSA methodology under the existing rules.

As explained in the McBride Testimony, the ISO's analysis found that using the proposed transfer capability methodology is consistent with applicable reliability standards and appropriately reflects the "higher of" methodology that is currently used for purposes of calculating the fixed zonal requirements in import-constrained zones. Specifically, it continues to account for N-1-1 conditions considered in the TSA assessment in determining an import-constrained capacity zone's transfer capability by enforcing a reduction in the transfer limit from the N-1 value used in the LRA assessment in conditions when the current 'higher of' methodology would set the existing fixed Local Sourcing Requirement based on the TSA. In contrast, as discussed in Section III.B of the McBride Testimony, the ISO has determined that other potential transfer capability methods that would apply more conservative assumptions (*i.e.* lower transfer capabilities) would procure capacity in excess of the current reliability standards for import-constrained zones.

F. MRI-Based Demand Curves Signal the Reliability Impact of Adding Capacity to Export-Constrained Capacity Zones

As noted earlier, an MRI-based demand curve for an export-constrained zone generally is developed using the same methodology that is used to develop an MRI-based curve for an import-constrained zone. However, the resulting shape of the demand curve for an export-constrained zone is different because the reliability impact is different when transferring capacity from the Rest-of-Pool Capacity Zone to an export-constrained zone rather than an import-constrained zone. An MRI-based demand curve for an export-constrained zone is relatively flat at low capacity quantities because the export transmission limit rarely or never binds and there is a negligible difference in the marginal reliability impact of adding capacity in either the export-constrained zone or in the Rest-of-Pool Capacity Zone. As the quantity of capacity in the export-constrained zone increases, however, the marginal reliability impact of adding more capacity to the export-constrained zone becomes progressively more significant, and the MRI curve for an export-constrained zone becomes progressively steeper – as reliability would actually be worse by adding the same amount of capacity in the export-constrained zone rather than in the Rest-of-Pool Capacity Zone. Accordingly, an MRI-based demand curve for an export-constrained zone is concave, starting out relatively flat and then sloping steeply downward. Figure 4 shows a representation of an MRI-based demand curve for an export-constrained zone.

[12] Section III.C of the McBride Testimony explains that when TSA exceeds LRA, the transfer capability used to define the MRI-based curves will be the N-1 value used for LRA purposes minus the positive difference between the TSA and LRA (*i.e*. TSA - LRA).

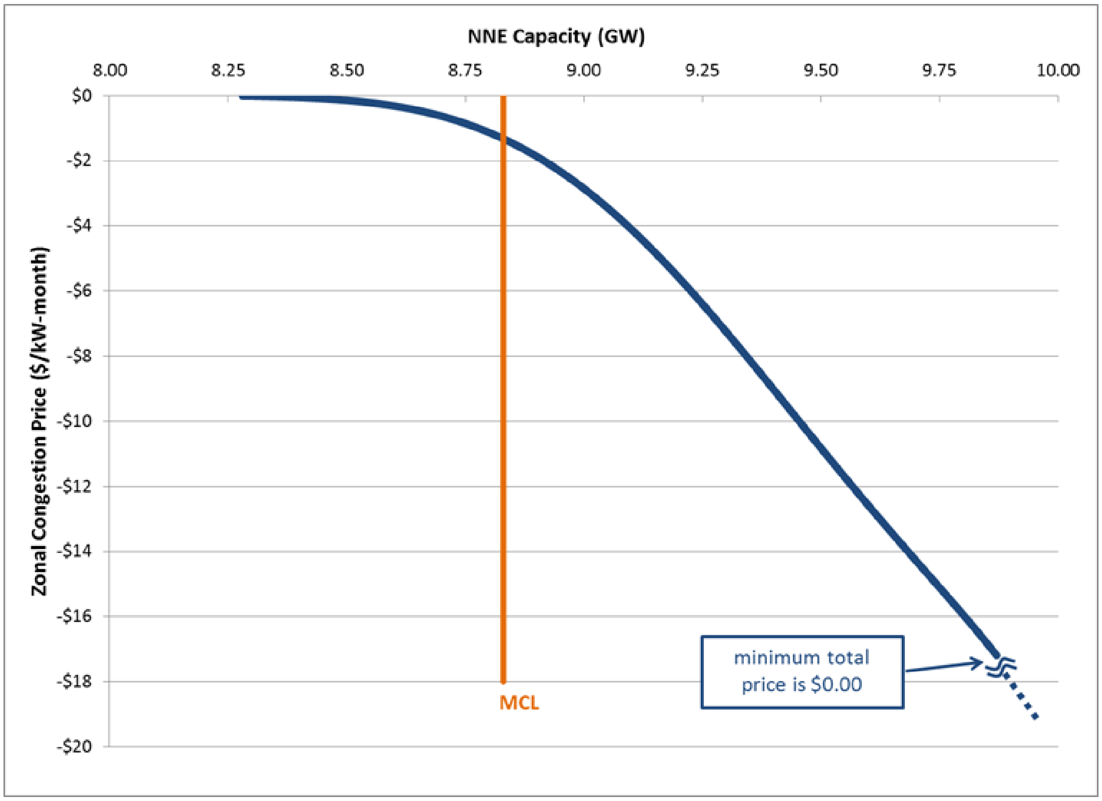

Figure 4

As with the import-constrained zones, MRI-based demand curves for export-constrained zones specify congestion prices. In other words, the demand curve for an export-constrained zone indicates what the appropriate price difference should be between the export-constrained zone and the Rest-of-Pool Capacity Zone. The price difference for an export-constrained zone is negative (or zero) because adding capacity to the Rest-of-Pool Capacity Zone improves reliability more than adding capacity in the export-constrained zone. At low capacity quantities within the export-constrained zone, the congestion price is zero because capacity in the export-constrained zone and Rest-of-Pool Capacity Zone provide the same reliability impact and capacity in the export-constrained zone and in the Rest-of-Pool Capacity Zone receives the same price. When the quantity of capacity located in an export-constrained zone is high, the congestion price is negative because adding capacity in the export-constrained zone improves reliability less than adding capacity in the Rest-of-Pool Capacity Zone and, therefore, capacity in the export-constrained zone is paid less than capacity in the Rest-of-Pool Capacity Zone.

G. Modifying the Existing System-Wide Capacity Demand Curve Maximizes the Benefit of the New MRI Methodology

The existing System-Wide Capacity Demand Curve represents demand as a straight line that is capped at the Forward Capacity Market Starting Price up to a capacity quantity of approximately 97% of Net ICR and then slopes downward to a price of $0.00/kW-month at a quantity of approximately 108% of Net ICR. As noted earlier, the design of the existing system demand curve was developed using an approach that was different than the approach used to develop the new MRI-based zonal demand curves.

Due to the differences in design approach, it is not possible to retain the existing design of the System-Wide Capacity Demand Curve and achieve the full benefits of the new MRI-based methodology.[13] For example, the full economic benefits associated with evaluating the cost-effectiveness of adding capacity at the system or zonal levels cannot be realized if the system demand curve is not based on MRI values.[14]

Due to the interrelatedness of the system and zonal demand curves, the ISO has concluded that it is not reasonable to continue to use a different approach to developing each curve over the long term. To maximize the benefits of using the new MRI-based approach, the Demand Curve Design Improvements would, following a brief transition period, use the new MRI methodology to develop the System-Wide Capacity Demand Curve. As discussed in more detail in Section IV.I of this filing letter, during the transition period, the System-Wide Capacity Demand Curve would be a hybrid of the existing linear demand curve design and the new MRI-based design. For the reasons noted above, the ISO believes that modifying the System-Wide Capacity Demand Curve to use the same MRI-based design as the zonal demand curves is necessary to achieve a fully functional, robust and efficient overall capacity market structure in the long term.

H. The Commission Should Approve the Zonal and System Demand Curve Design Improvements Together

During stakeholder consideration of the MRI-based approach to developing demand curves, there was some discussion concerning whether changes to the System-Wide Capacity Demand Curve should be filed and considered separately from the new MRI-based zonal sloped demand curves. The ISO presented, and stakeholders reviewed, the zonal and system curves together, and the Demand Curve Design Improvements are being filed together in the same manner. NEPOOL and the ISO together urge the Commission to approve the zonal and system curves, with the transition period, as filed.

When considering the scope of what changes may be filed in response to a compliance directive, the Commission has found that it is acceptable to file changes that are "closely and plainly" related to the compliance directive.[15] In the ISO's view, it is clear that changing the

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[13] *See* Section VI of the Geissler-White Testimony.

[14] *Id.*

[15] *See Midwest Independent Transmission System Operator, Inc*., 112 FERC ¶ 61,169 at P 15 (2005). In that order, the Commission stated:

> The Commission generally does not permit public utilities to submit rate filings under section 205 of the FPA together with compliance filings. The Commission has, however, accepted a section 205 filing in combination with a compliance filing when the compliance directives in question warranted changes to other, related tariff provisions.

(continued...)

System-Wide Capacity Demand Curve so that it is compatible with the new overall structure for representing demand in the capacity market is "closely and plainly" related to the changes to the zonal demand curves.[16] It should be noted that NEPOOL did not specifically vote on, and does not have a position on, the question of whether or not the proposed modifications to the System-Wide Capacity Demand Curve are "closely and plainly" related to the changes to the zonal demand curves.

I. The Transition to a New System-Wide Capacity Demand Curve Creates a Stable Path Between Designs

The Demand Curve Design Changes provide for a transition from the existing linear System-Wide Capacity Demand Curve to the new MRI-based system curve. As explained in the Geissler-White Testimony, the transition period may last no longer than three auctions. During this period, the transition curve is a hybrid of the existing linear demand curve design and the new MRI-based design. The length of the transition period (referred to as the MRI Transition Period) depends on whether certain conditions are met. Most importantly, the transition period ends and the new MRI-based system curve is implemented in the next auction if load growth (specifically, Net ICR) increases above certain specified levels.

The purpose of the transition is to provide a stable and predictable path from the existing design, and its market signals, to the new design. Without a transition, project developers that already have begun the lengthy process of developing a new resource based on their expectations concerning the existing market design and the relatively recently implemented linear system demand curve, could find that their market expectations have changed considerably just at the time that they are ready to qualify a resource to participate in the next auction. In the absence of a transition, an immediate and abrupt switch from the existing linear demand curve to the new MRI-based system demand curve would shift the system demand curve significantly to the left

(...continued)

> The tariff changes proposed here are closely and plainly related to the Commission's compliance requirements. In addition, the proposed rate changes show a common factual nexus with the compliance filing and do not undo or contravene the compliance requirements. As such, on these facts we will consider the section 205 filing in this proceeding.

[16] If the Commission concludes that the changes to the system curve are beyond the scope of this proceeding, the ISO requests that the Commission treat that portion of this filing as a Section 205 filing and approve the changes under the traditional Section 205 standard; taking the same approach as it took in the proceeding approving the system-wide demand curve, the seven-year price lock option and the renewable resource offer review exemption. *ISO New England Inc. and New England Power Pool Participants Committee, Order Accepting Tariff Revisions*, 147 FERC ¶ 61,173 at P 61 (2014). Alternatively, if the Commission rejects the changes to the System-Wide Capacity Demand Curve as being outside of the scope of what may be filed in this proceeding, the ISO will immediately re-file those changes pursuant to Section 205 so that the changes could still be in place before FCA 11 along with the rest of the Demand Curve Design Improvements.

for a wide range of prices, which may suddenly and unexpectedly lower anticipated short-term clearing prices and increase the perceived investment risk associated with developing new capacity in New England. The ISO also has concluded that a transition mechanism should help maintain developer/investor confidence in the market and may lower the risk of higher bid prices that could result from a perception of an unstable, riskier market. Notably, the use of a transition mechanism was strongly supported by a broad cross-section of stakeholders, including those that represent the interests of both consumers and suppliers.[17]

J. The Demand Curve Design Improvements Eliminate the Need for Administrative Pricing Rules

The Demand Curve Design Improvements include the elimination of the remaining administrative pricing rules that have been used in the capacity market to protect against the potential exercise of market power. Specifically, the administrative pricing rules that are being removed are the Capacity Carry Forward Rule (Section III.13.2.7.9) and the rules concerning Inadequate Supply and Insufficient Competition (both in Section III.13.2.8).

As the Commission stated in the December 28 Order, the continued application of vertical demand curves within constrained zones does not sufficiently address the susceptibility of such a design to the exercise of market power.[18] In contrast, the Commission has recognized that appropriately designed sloped demand curves reduce the susceptibility of the capacity market to the exercise of market power and provide a basis for eliminating administrative pricing rules.[19] The Demand Curve Design Improvements will put in place sloped zonal demand curves that are much more resistant to the exercise of market power and thereby facilitate the elimination of the administrative pricing rules. As discussed in Section IX of the Geissler-White Testimony, the design of the new sloped zonal demand curves reduces the risk of the exercise of market power in three ways. First, compared to vertical curves, the new sloped demand curves are not as susceptible to market power because price changes more gradually in response to changes in supply when sloped demand curves are used. Second, the new design allows for the substitution of supply between capacity zones which means that there are more resources competing against each other and that the opportunity to exercise market power is reduced. Finally, the application of the "maximize social surplus" principle to the clearing of the entire market, including constrained zones, makes it more difficult for suppliers to gauge whether a supply bid will clear when market conditions are tight.

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[17] For further information concerning the ISO's views on the transition mechanism, *see*, Memorandum to NEPOOL Participants Committee and Markets Committee, "Capacity Demand Curves – Transition Approach," dated March 31, 2016, which can be found here: http://www.iso-ne.com/static-assets/documents/2016/04/npc_20160408_composite3.pdf

[18] December 28 Order at P 15.

[19] *ISO New England Inc. and New England Power Pool Participants Committee, Order Accepting Tariff Revisions,* 147 FERC ¶ 61,173 at P 29 (2014), *Order Denying Rehearing, Providing Clarification and Directing Further Compliance Filing*, 150 FERC ¶ 61,065 (2015).

While the replacement of the vertical demand curves with sloped demand curves is needed in order to allow for the removal of administrative pricing rules, the ISO and its market monitors believe that the use of sloped demand curves does not by itself fully protect against the potential exercise of market power.[20] In the New England market, the ISO's market monitors have both recognized that the capacity market also requires the use of some level of offer/bid review and mitigation in order to protect against both supplier-side and buyer-side market power. While the existing capacity market generally has an effective review and mitigation structure in place, the ISO's market monitors concluded that this structure would not be complete in the absence of the "Forward Capacity Market Retirement Reforms" that were filed by the ISO in Docket No. ER16-551 and conditionally accepted by the Commission a few days ago in an order issued on April 12, 2016.[21] The Forward Capacity Market Retirement Reforms include important rules that will protect against the exercise of market power through the uneconomic retirement of an existing resource. These Commission-accepted reforms, in combination with the new zonal demand curves, make it possible to eliminate the existing administrative pricing rules, to protect against the exercise of market power in the form of an uneconomic retirement.

K. The Demand Curve Design Improvements Required Review of Reconfiguration Auction and Related Rules

The Demand Curve Design Improvements include conforming changes to the annual reconfiguration auction rules in Section III.13.4.5. These limited changes provide that the existing design, in which each primary Forward Capacity Auction and its associated reconfiguration auctions are conducted using the same overall framework, will continue to apply when the sloped zonal demand curves are introduced. In other words, if a primary auction was conducted using a vertical zonal demand curve, then the associated reconfiguration auctions will use a vertical zonal demand curve. If a primary auction was conducted using sloped zonal demand curves, the associated reconfiguration auctions will use sloped zonal demand curves.

The ISO and stakeholders have recognized that it may be appropriate to make additional conforming or other changes to the rules for annual reconfiguration auctions, monthly reconfiguration auctions and Capacity Supply Obligation Bilaterals. However, there was not sufficient time to fully consider what changes would be appropriate prior to the April 15, 2016 deadline for submitting this filing. The ISO plans to consider and review with stakeholders whether any additional changes should be made to address these topics prior to the occurrence in 2018 of the first reconfiguration auction or bilateral transaction windows under the new sloped zonal demand curve framework. The ISO currently expects to begin reviewing these issues through the stakeholder process in the first half of 2017.

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[20] The market monitors' views are set out in memoranda that they provided to the NEPOOL Markets Committee in January 2016. The memoranda are included as Attachment 3 (Internal Market Monitor) and Attachment 4 (External Market Monitor) of the Geissler-White Testimony.

[21] *ISO New England Inc., Order Accepting Tariff Filing Subject to Condition*, 155 FERC ¶ 61,029 (2016).

V. DESCRIPTION OF TARIFF REVISIONS

This section provides a guide to the ISO Tariff revisions associated with the Demand Curve Design Improvements.

The revisions begin with several changes to the ISO Tariff definitions in Section I.2.2. The definition changes add two new terms: "Capacity Zone Demand Curves" and "Marginal Reliability Impact." Capacity Zone Demand Curves is the generic term used to refer to the demand curves that will be used in the Forward Capacity Market for each import-constrained and export-constrained Capacity Zone. The specific shape of each Capacity Zone Demand Curve is determined for each Capacity Zone that is used in an auction pursuant to new rules that are set out in Sections III.13.2.2.2 and III.13.2.2.3. Marginal Reliability Impact is the new term that refers to the calculated change in reliability associated with adding an increment of capacity at a particular location, which is a key component in determining the shape of the new system and zonal demand curves. In addition to adding two new terms, a number of existing terms are removed because they are obsolete due to the removal of the administrative pricing provisions or for other reasons. The removed terms include: Inadequate Supply, Insufficient Competition, New Capacity Required and Successful FCA.

The next series of changes occur in Section III.12, the section of the rules that governs the development of key inputs for each Forward Capacity Auction. The changes to this section remove the rules relating to the use of "LOLE" values to determine the System-Wide Capacity Demand Curve in Section III.12.1. Instead, in keeping with the approach in the Demand Curve Design Improvements, the rules now provide for calculating Marginal Reliability Impact values at the system level (Section III.12.2.1.1), for each import-constrained capacity zone (Section III.12.2.1.3) and for each export-constrained capacity zone (Section III.12.2.2.1). Section III.12.3 is modified to provide that the ISO shall review with stakeholders and file with the Commission the modeling and assumptions (the chief of which are the Marginal Reliability Impact values) used to determine the capacity market demand curves prior to each auction. The stakeholder review and filing process for the demand curves is the exact same process as currently is used for the Installed Capacity Requirement and related values. The remaining changes to Section III.12 simply conform the existing rules to the new approach that involves using Marginal Reliability Impact values, rather than LOLE values, to determine the shape of the capacity market demand curves. For example, in Section III.12.7.1, the words "capacity requirement values for the System-Wide Capacity Demand Curve" (which refers to LOLE values) are replaced by the words "Marginal Reliability Impact values."

The bulk of the ISO Tariff revisions are to Section III.13, the market rules that govern the administration of the Forward Capacity Market. The changes to this section are summarized as follows:

- There are a number of new provisions concerning the design of the new capacity market demand curves. First, new sections are added to specify how demand curves, based on the Marginal Reliability Impact values calculated pursuant to Section III.12, are derived at the system-wide level (Section III.13.2.2.1), for import-constrained capacity zones (Section III.13.2.2.2) and for export-constrained capacity zones (Section III.13.2.2.3). Next, Section III.13.2.2.4 specifies that the "scaling factor" that is applied to translate each set of Marginal Reliability Impact values into demand curves is based on the principle that the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE must correspond to a Loss of Load Expectation of 0.1 days per year. Finally, the old rules specifying the method of determining the System-Wide Capacity Demand Curve using LOLE values is removed.

- Section III.13.2.2.1 specifies the rules for transitioning the existing linear demand curve design of the System-Wide Capacity Demand Curve to the new MRI-based design. The rules define the new term "MRI Transition Period" as a period that may last no longer than three capacity market auctions and that can terminate earlier if certain conditions are met. The rules provide that a new transitional demand curve design will be used during the MRI Transition Period. Following the transition period, the new MRI-based demand curve is used (no later than FCA 14).

- The rules governing the conduct of auction rounds and the calculation of clearing prices (contained in Section III.13.2.3.3 (Step 3: Determination of the Outcome of Each Round)) include many revisions to reflect the new approach taken by the Demand Curve Design Improvements. For purposes of this section, the most important aspect of the various changes is that auction rounds are closed in a manner consistent with the interdependent clearing of capacity between Capacity Zones pursuant to the new demand curves. Furthermore, the changes reflect that the Capacity Clearing Prices in import-constrained and export-constrained capacity zones are set using a congestion pricing method (for example, the price in an import-constrained capacity zone equals the price for the Rest-of-Pool Capacity Zone plus any incremental price calculated for the import-constrained zone). Most of the other changes reflect auction clearing rules that are important and necessary, but only apply in special situations.

- Section III.13.2.7 is revised to set out pricing rules that: (1) cap the clearing prices in the Rest-of-Pool Capacity Zone and any import-constrained capacity zones at the Forward Capacity Auction Starting Price, and; (2) set a floor price of zero for the clearing price in any export-constrained capacity zone (prices for an export-constrained capacity zone cannot be negative).

- There are several changes to the rule governing the clearing of "lumpy" offers using the capacity rationing process set out in Section III.13.2.7.4. The changes reflect that this process no longer procures a fixed requirement and instead now clears capacity to maximize social surplus consistent with the design of the new Capacity Zone Demand Curves.

- The existing rules that provide for administrative pricing in certain situation are removed, as are provisions that cross reference these administrative pricing rules.

The removed sections include the Capacity Carry Forward Rule (Section III.13.2.7.9) and the rules concerning Inadequate Supply and Insufficient Competition (both in Section III.13.2.8).

- While the rules for calculating administrative prices are removed because they will not be used in any auctions going forward, it is necessary to retain references to administrative prices that were calculated for certain prior auctions because these prices serve to establish the payment rate that is still to be applied for the Capacity Commitment Periods associated with these auctions.[22] The revised rules refer to these previously-determined administrative prices as "the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015." Most of these revised references to previously-calculated administrative prices are in Section III.13.2.7.

- Section III.13.4.5 of the existing rules provides that reconfiguration auctions are conducted using the same framework as was used in the primary Forward Capacity Auction that is associated with the particular reconfiguration auction. The ISO Tariff revisions include a conforming change to specify that the use of the same framework for a primary FCA and its associated reconfiguration auctions includes the use of the same "capacity demand curves."

The revisions also include a small change to Appendix A, the market monitoring section of the ISO Tariff. This change revises Section III.A.24.v to reflect that the Internal Market Monitor's estimation of capacity prices pursuant to the retirement portfolio test is based on both the System-Wide Capacity Demand Curve and the new "Capacity Zone Demand Curves."

VI. STAKEHOLDER PROCESS

The Demand Curve Design Improvements were considered through the complete NEPOOL Participant Processes. At its March 18, 2016 meeting, the NEPOOL Markets Committee voted to recommend that the NEPOOL Participants Committee support the provisions of an earlier version of the Demand Curve Design Improvements that are included in Market Rule 1, Section III.13 and Appendix A to Market Rule 1 and Tariff Section I.2.2 by a vote of 74.05%.[23] On March 23, 2016, the NEPOOL Reliability Committee voted to recommend support for the provisions of the Demand Curve Design Improvements that are included in Market Rule 1, Section III.12 and Tariff Section I.2.2 by a vote 90.30%. Finally, at its April 8,

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[22] Specifically, the administrative pricing rules were applied in FCA 7, FCA 8 and FCA 9 and the Capacity Commitment Periods for these auctions will not be completed until June 1, 2019. Administrative pricing rules were not applied in FCA 10, which was held in February 2016.

[23] Pursuant to the Participants Agreement, a vote of at least 60% is required for support of any proposed Market Rule changes and a vote of at least 66-2/3% is required for support of any other proposed change. Market Rules are included in Section III of the Tariff.

2016 meeting, the Participants Committee voted to support the package of Demand Curve Design Improvements reflected in this filing by a vote of 75.94% in favor.[24]

VII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the Demand Curve Design Improvements do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations.[25] Notwithstanding the request for waiver, the Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations:

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

- This transmittal letter;
- Blacklined ISO Tariff sections reflecting the revision submitted in this filing;
- Clean ISO Tariff sections reflecting the revision submitted in this filing;
- Testimony of Christopher Geissler, Economist, and Matthew White, Chief Economist, sponsored solely by the ISO;
- Attachment 1 – Performance of Zonal Demand Curves
- Attachment 2 – December 2015 Technical Memo re Zonal Demand Curves
- Attachment 3 – IMM Memo re Zonal Demand Curves and Administrative Pricing
- Attachment 4 – EMM Comments on ISO-NE's Zonal Demand Curve Proposal
- Testimony of Alan McBride, Director, Transmission Strategy and Services, sponsored solely by the ISO;

[24] NEPOOL has indicated that it plans to submit comments in this proceeding to provide the Commission with additional information regarding stakeholder consideration of the Demand Curve Design Improvements and to present an explanation of proposed modifications to the Demand Curve Design Improvements that were considered in the stakeholder process (including information regarding the outcome of NEPOOL's votes on those proposed modifications).

[25] 18 C.F.R. § 35.13 (2014).

- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent.

35.13(b)(2) – As set forth in Section I above, the Filing Parties request that the changes become effective on June 15, 2016.

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 VII of this transmittal letter.

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

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

35.13(b)(7) – Neither the ISO nor NEPOOL has knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(b)(8) – A form of notice and electronic media are no longer required for filings in light of the Commission's Combined Notice of Filings notice methodology.

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

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

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

VIII. CONCLUSION

For the reasons discussed in this transmittal letter, the Filing Parties request that the Commission accept the Demand Curve Design Improvements to become effective on June 15, 2016.

Respectfully submitted,

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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.

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 costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

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

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

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

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

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.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

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

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

Category 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 the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

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

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

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

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

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

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

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

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

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

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

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

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

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.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.
Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

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

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

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

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

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

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

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, 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.

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

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

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

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

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(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 (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points and meets the criteria specified in Section III.1.11.3(e).

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator 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 for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, 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 Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

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

Existing Demand 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.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

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

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

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

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

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to

Dispatch Instructions or has automatic remote response capability; (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.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; and (iv) has satisfied its Minimum Down Time.

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 $9,000/megawatt-month.

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

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

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

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

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

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

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

FTR 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.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

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.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

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

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.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

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

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

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

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

Limited Energy Resource means 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.

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.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

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

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

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

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

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

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

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

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

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

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

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

Maximum Capacity Limit is 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 over-stated 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 (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

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

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

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

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

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

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

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

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.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

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

MW is megawatt.

MWh is megawatt-hour.

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

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

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

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

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

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

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

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

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

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

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

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; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

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

Non-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-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.13.1.2.3.1.5 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

Point(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.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a 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 costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

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

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

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

~~**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.

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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

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III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

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

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

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

~~The ISO shall determine, by applying the same modeling assumptions and methodology used in determining the Installed Capacity Requirement, the capacity requirement value for each LOLE probability specified in Section III.13.2.2 for the System-Wide Capacity Demand Curve.~~

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

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

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

Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction. The Local Sourcing Requirement shall represent the minimum amount of capacity that must be procured within an import-constrained Capacity Zone. The Maximum Capacity Limit shall represent the maximum amount of capacity that can be procured in an export-constrained Capacity Zone to meet the Installed Capacity Requirement.

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

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

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

III.12.2.1.1. Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

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

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

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

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

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

In which:

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

		resources within Capacity Zone Z, including and proxy unit additions to Capacity Zone Z.
Proxy Units Adjustment	=	MW of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1 days/year.

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

III.12.2.1.2. Transmission Security Analysis Requirement.

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

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

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

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

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

III.12.2.1.3. Marginal Reliability Impact Values for Import-Constrained Capacity Zones.
Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each import-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) shall be reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero.

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

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

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

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

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

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

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

In which:

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

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

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

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

III.12.3 Consultation and Filing of Capacity Requirements.

At least two months prior to filing the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, ~~and capacity requirement values for the~~ System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, ~~and capacity requirement values for the~~ System-Wide Capacity Demand Curve and Capacity Zone Demand Curves with the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, ~~and capacity requirement values for the~~ System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act 90 days prior to the Forward Capacity Auction for the Capacity Commitment Period. The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given FCA, any new Capacity Zone must have received approval from the Commission prior to the Existing Capacity Qualification Deadline of the applicable FCA.

III.12.4. **Capacity Zones.**

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

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

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

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

III.12.5. Transmission Interface Limits.

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

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

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

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

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

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

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

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

III.12.6.1. Process for Establishing the Network Model.

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

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

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

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

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

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

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

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

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

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

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

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

III.12.6.3. Evaluation Criteria.

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

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

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

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

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

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

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

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

III.12.7. Resource Modeling Assumptions.

III.12.7.1. Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as additional capacity to determine the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values~~capacity requirement values for the System-Wide Capacity Demand Curve~~. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all other resources in the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

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

III.12.7.2. Capacity.

The resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values ~~capacity requirement values for the System-Wide Capacity Demand Curve~~ shall include:

(a) all Existing Generating Capacity Resources,

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

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

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

but shall exclude:

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

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

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

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

III.12.7.2.1. **[Reserved.]**

III.12.7.3. **Resource Availability**.

The Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values ~~capacity requirement values for the System-Wide Capacity Demand Curve~~ shall be calculated taking resource availability into account and shall be determined as follows:

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values~~capacity requirement values for the System-Wide Capacity Demand Curve~~. The most recent five-year moving average of EFORd shall be used as the measure of resource availability for non-peaking resources used in the calculation of Transmission Security Analysis Requirements. A deterministic adjustment factor, based on the operational experience of the ISO, shall be used as the measure of resource availability for peaking resources used in the calculation of Transmission Security Analysis Requirements, and will be reviewed periodically.

(b) [Reserved.]

(c) Once sufficient data are collected under the availability incentives in the Forward Capacity Market, a resource availability metric, which reflects resource availability in a manner that is consistent with the availability incentives in the Forward Capacity Market, shall be developed and reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies and used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values~~capacity requirement values for the System-Wide Capacity Demand Curve~~.

For resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that do not have sufficient data to calculate an availability metric as defined in subsections (a) or (c) above, class average data for similar resource types shall be used. For Demand Resources, including Real-Time Emergency Generation, historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values~~capacity requirement values for the System-Wide Capacity Demand Curve~~.

III.12.7.4. **Load and Capacity Relief.**

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

(a) **Implement voltage reduction**. The MW value of the load relief shall be equal to the percentage load reduction achieved in the most applicable voltage reduction tests multiplied by the forecasted seasonal peak loads.

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

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

III.12.8. **Load Modeling Assumptions**.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias. Demand Resources shall be reflected in the load forecast as specified below:

(a) Expected reductions from an installed or forecast Demand Resource not qualifying for or not participating in the Forward Capacity Auction shall be reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values ~~capacity requirement values for the System-Wide Capacity Demand Curve~~ for the relevant Capacity Commitment Period. The expected reduction from these resources will be included in the load forecast to the extent that they meet the qualification process rules, including monitoring and verification plan and financial assurance requirements. If no qualification process rules are in place for the expected reductions from these resources, they shall not be included within the load forecast.

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

(c) [Reserved.]

(d) Any realized Demand Resource reductions in the historical period that received Forward Capacity Market payments for these reductions, or Demand Resource reductions that are expected to receive Forward Capacity Market payments by participating in the upcoming Forward Capacity Auction or having cleared in a previous Forward Capacity Auction, shall be added back into the appropriate historical loads to ensure that such resources are not reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum

Capacity Limits and Marginal Reliability Impact values ~~capacity requirement values for the System-Wide Capacity Demand Curve~~ for the relevant Capacity Commitment Period.

III.12.9. Tie Benefits.

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

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

III.12.9.1. Overview of Tie Benefits Calculation Procedure.

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

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

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

III.12.9.1.2. Tie Benefits Calculation.

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

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

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

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

III.12.9.2.1. Assumptions Regarding System Conditions.

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

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

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

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

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

III.12.9.2.4. Other Modeling Assumptions.

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

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

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

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

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

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

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

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

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

B. **Removing capacity from New England when the New England system is surplus of capacity.** In modeling New England as part of the interconnected system, if New England is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in these surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the

Existing Qualified Capacity, and any amount of proxy units added in that sub-area that is above its 50-50 peak load forecast. Notwithstanding the foregoing, if removing resources will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratios described above for the removal of capacity surplus. If there are no modeled internal transmission constraints in the New England Control Area, then the surplus capacity shall be removed from the entire Control Area.

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

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

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

III.12.9.3. Calculating Total Tie Benefits.

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

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

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

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

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

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

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

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

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

III.12.9.5. Calculating Tie Benefits for Individual Ties.

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

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

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

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

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

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

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

III.12.9.6.1. Accounting for Capacity Imports.

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

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

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

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

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

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

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

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

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

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

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

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

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

(iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

(1) at prices above $7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;

(2) at prices below $7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between $7.03/kW-month and $0.00/kW-month and determined by the following quantities:

(a) At the price of $0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.

(b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,437 MW; and
2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,090 MW; and
2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at $7.03/kW-month, the quantity shall be the lesser of:

1. 34,865 MW; and
2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month

(3) a price of $7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

~~The System-Wide Capacity Demand Curve is defined as follows:~~

~~(a) For quantities less than the Installed Capacity Requirement (net of HQICCs) at 0.200 LOLE, the price is max [1.6 multiplied by Net CONE, CONE];~~

~~(b) For quantities equal to or greater than the Installed Capacity Requirement (net of HQICCs) at 0.200 LOLE, but less than 0.011 LOLE, the price will be determined by a straight line between the price at 0.200 LOLE (which shall be max [1.6 multiplied by Net CONE, CONE] and the price at 0.011 LOLE (which shall be zero);~~

~~For quantities equal to or greater than the Installed Capacity Requirement (net of HQICCs) at 0.011 LOLE, the price is zero.~~

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \leq p_1, \\ q_2, & \text{if } p_3 < p \leq p_2, \\ \cdots & \quad \cdots \quad , \\ q_m, & \text{if } p \leq p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic Delist Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be bid into the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section

III.13.2.3.2(c). Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the

End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 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 a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5.

Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

~~-~~The aggregate supply curve for the New England Control Area, ~~(~~the ~~“~~Total System Capacity~~”)~~, shall reflect at each price the sum of the following:~~(~~

(1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);~~) plus (~~

(2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);~~) plus (~~

(3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:

(i) ~~-~~the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits)~~)~~, or;

(ii) ~~-~~the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price~~'s Maximum Capacity Limit) plus (~~, and;

(4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:

(i) that interface's approved capacity transfer limit (net of tie benefits), or;

(ii) ~~-~~the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources~~)~~.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. ~~In no event shall the Capacity Clearing Price for a Capacity Zone be greater than the Forward Capacity Auction Starting Price for that Capacity Zone.~~ On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price)~~Capacity Zone's Local Sourcing Requirement;~~, or;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

~~(2) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve;~~

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the ~~highest price at which either of the two conditions above are satisfied,~~ greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then the auctioneer shall publish ~~the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price) and~~ the quantity of capacity in the Capacity Zone from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**.

~~For the Rest-of-Pool Capacity Zone, i~~If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

~~If the Total System Capacity exceeds~~ If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price, ~~then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price)~~ and also shall publish the quantity of capacity from Demand Resources by type at the End-of-Round Price~~, and the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction~~.

(c) **Export-Constrained Capacity Zones**. For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

~~(i)~~

(1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or ~~below~~ less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero~~'s Maximum Capacity Limit;~~, and;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

~~(ii) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve;~~

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the ~~highest price at which both of the conditions above are satisfied~~greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the export-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish ~~the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price) and~~ the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero~~Maximum Capacity Limit of the export-constrained Capacity Zone~~) and the quantity of capacity in the Capacity Zone from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for ~~Local Sourcing Requirement of~~ the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

(f) **Treatment of Real-Time Emergency Generation Resources.** In determining when the Forward Capacity Auction is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation Resources shall be counted towards meeting the cleared amount of capacity determined by the System-Wide Capacity Demand Curve. If the sum of the Capacity Supply Obligations of Real-Time Emergency Generation Resources exceeds 600 MW, the Capacity Clearing Price~~, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b))~~, or, if applicable, the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015, paid to all Real-Time Emergency Generation Resources shall be adjusted by the ratio of 600 MW divided by the total of the final Capacity Supply Obligations of Real-Time Emergency Generation Resources. A Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, Permanent De-list Bid, or Retirement De-List Bid shall clear based on the effective Capacity Clearing Price as described in Section III.13.2.7.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2018 is $14.04/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2018 is $11.08/kW-month.

CONE and Net CONE shall be recalculated using updated data coincident with the recalculation of Offer Review Trigger Prices pursuant to Section III.A.21.1.2. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e), except that the energy and ancillary services offset will be adjusted using publicly available data for Mass Hub On-Peak electricity futures through the commitment period of the FCA and will not be adjusted based on natural gas prices. Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5~~ and Section III.13.2.5.2.7~~, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the bid has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated if either of the following conditions is met in the initial auction clearing process: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation); or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation) and the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price. The second run of the auction-clearing process: (i) excludes all Proxy De-List Bid(s), (ii) includes the offers and bids of resources that did not receive a Capacity Supply Obligation in the first run of the auction-clearing process, and (iii) includes the capacity of resources, or portion thereof, that received a Capacity Supply Obligation in the first run of the auction-clearing process. The second run of the auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) that receive a Capacity Supply Obligation as a result of the first run of the auction-clearing process shall be paid the Capacity Clearing Price~~, as adjusted pursuant to Sections III.13.2.7.9 and III.13.2.8,~~ during the associated Capacity Commitment Period. Where the second run of the auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5~~ and Section III.13.2.5.2.7~~, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource’s Economic Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price~~ and regardless of whether there is Inadequate Supply or Insufficient Competition in the Capacity Zone~~.

III.13.2.5.2.5. Reliability Review.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid to determine whether the capacity associated with that de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station.. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. De-list bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) Where a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction.

(c) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject the de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability. Resources that submitted Permanent De-List Bids or Retirement De-List Bids shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii)).

(g) If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1.

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

~~In instances where~~ If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or

Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the "just and reasonable" standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the Capacity Commitment Period for which the Retirement De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: submitted a Retirement De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III.13.1.2.3.1.5(d); elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction; or, for a resource, or portion thereof, that submitted a Permanent De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the Capacity Commitment Period for which its Permanent De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: submitted a Permanent De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III. III.13.1.2.3.1.5(d); was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

~~III.13.2.5.2.6. [Reserved.]~~

~~III.13.2.5.2.7. Treatment of De-List and Export Bids When the Capacity Clearing Price is Set Administratively.~~

~~Where the Capacity Clearing Price is set pursuant to Section III.13.2.7.9 (Capacity Carry Forward Rule), or where payments are set pursuant to Section III.13.2.8 (Inadequate Supply and Insufficient Competition), and as a result a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, or~~

~~Export Bid clears that would not otherwise have cleared, then the de-listed or exported capacity will not be replaced in the current Forward Capacity Auction (that is, the amount of capacity procured in the Forward Capacity Auction shall be the Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices).~~

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for each import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.
The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. Capacity Clearing Price Floor.
In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below $3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches $3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to $3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.

(ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).

(iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource's payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply 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 Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5.

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.
Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more~~a~~ Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, ~~required,~~ then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that ~~result in procuring at least the amount of capacity required while~~ seeking to maximize social surplus for the associated Capacity Commitment Period. ~~In an import-constrained Capacity Zone, the clearing algorithm will not consider blocks of capacity not needed to meet the import-constrained Capacity Zone's Local Sourcing Requirement when price separation occurs between the import-constrained Capacity Zone and the Rest-of-Pool Capacity Zone.~~ The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.
Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.
Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a

Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) [Reserved.]

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources) shall be cleared.

~~**III.13.2.7.8. [Reserved.]**~~

~~**III.13.2.7.9 Capacity Carry Forward Rule.**~~

~~**III.13.2.7.9.1. Trigger.**~~

~~The capacity carry forward rule shall be triggered in an import-constrained Capacity Zone if all of the following conditions are met:~~

~~(a) the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids and Retirement De-List Bids clearing in the Forward Capacity Auction in the Capacity Zone is less than or equal to zero;~~

~~(b) there is not Inadequate Supply in the Forward Capacity Auction in the Capacity Zone; and~~

~~(c) at the Capacity Clearing Price, the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids and Retirement De-List Bids clearing in the Forward Capacity Auction plus the amount of capacity carried forward due to rationing is greater than zero. The amount of capacity carried forward due to rationing shall equal the amount of capacity above the Local Sourcing Requirement procured in that Capacity Zone in the previous Forward Capacity Auction as a result of the Capacity Rationing Rule.~~

~~III.13.2.7.9.2. Pricing.~~

~~If the capacity carry forward rule is triggered, then the Capacity Clearing Price for the Capacity Zone shall be the lesser of: (1) $0.01 below the price at which the last New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource in the Capacity Zone to withdraw withdrew from the Forward Capacity Auction; or (2) the applicable Net CONE value; provided, however, that if in the Capacity Zone there is Insufficient Competition and no capacity offered from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources has been withdrawn from the Forward Capacity Auction, then the Capacity Clearing Price shall equal the applicable Net CONE value.~~

~~III.13.2.8. Inadequate Supply and Insufficient Competition.~~

~~In the case of either Inadequate Supply or Insufficient Competition, as defined in this Section III.13.2.8, the Forward Capacity Auction shall still be used to the extent possible; that is, the remedy for Inadequate Supply or Insufficient Competition shall be limited to import-constrained Capacity Zones having Inadequate Supply or Insufficient Competition.~~

~~III.13.2.8.1. Inadequate Supply.~~

~~III.13.2.8.1.1. Inadequate Supply in an Import-Constrained Capacity Zone.~~

~~An import-constrained Capacity Zone will be considered to have Inadequate Supply if at the Forward Capacity Auction Starting Price the amount of capacity offered in the import-constrained Capacity Zone through New Capacity Offers is less than the amount of New Capacity Required in that Capacity Zone. In an import-constrained Capacity Zone, "New Capacity Required" shall mean the Capacity Zone's Local Sourcing Requirement minus (the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period) plus the capacity of Proxy De-List Bids entered as result of a retirement election pursuant to Section III.13.1.2.4.1(a)) minus capacity otherwise obligated in the Capacity Zone for the Capacity Commitment Period.~~

~~(a) Where an import-constrained Capacity Zone has Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) in that Capacity Zone, other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid the max [applicable Net CONE value, Capacity Clearing Price for the Rest-of-Pool Capacity Zone] during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction in that Capacity Zone shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).~~

~~(b) [Reserved.]~~

~~(c) Inadequate Supply in one or more import-constrained Capacity Zones shall not affect Capacity Zones having adequate supply.~~

~~(d) Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Inadequate Supply will be assessed at a rate equal to $7.025/kW-month.~~

~~III.13.2.8.1.2. [Reserved.]~~

~~III.13.2.8.2. Insufficient Competition~~~~.~~

~~The Forward Capacity Auction shall be considered to have Insufficient Competition in an import-constrained Capacity Zone if there is not Inadequate Supply and the following two conditions are both satisfied:~~

~~(a) at the Forward Capacity Auction Starting Price, the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (that is not permanently de-listed for the Capacity Commitment Period), plus the capacity of Proxy De-List Bids entered as as result of a retirement election pursuant to Section III.13.1.2.4.1(a), minus capacity otherwise obligated for the Capacity Commitment Period, is less than the Local Sourcing Requirement; and~~

~~(b) at the Forward Capacity Auction Starting Price:~~

~~(i) less than 300 MW of capacity is offered from New Generating Capacity Resources and New Demand Resources (the ISO shall revisit the appropriateness of the 300 MW threshold in the case of an import-constrained Capacity Zone having a Local Sourcing Requirement of less than 5000 MW);~~

~~(ii) the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is less than twice the amount of New Capacity Required; or~~

~~(iii) any Market Participant's total capacity from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources is pivotal. For purposes of this Section III.13.2.8.2, a Market Participant shall be considered pivotal if, at the Forward Capacity Auction Starting Price, some capacity from that Market Participant's potential New Generating Capacity Resources, New Import Capacity Resources, or New Demand Resources is required to satisfy the Local Sourcing Requirement.~~

~~If the Forward Capacity Auction has Insufficient Competition, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) shall be paid the lower of: (1) the Capacity Clearing Price; or (2) max [applicable Net CONE value, the~~

~~Capacity Clearing Price for the Rest-of-Pool Capacity Zone] during the associated Capacity Commitment Period. Notwithstanding the foregoing, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) that cleared in the seventh Forward Capacity Auction in the NEMA Capacity Zone shall be paid $6.661/kW-month and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) that cleared in the eighth Forward Capacity Auction in all Capacity Zones but the NEMA Capacity Zone shall be paid $7.025/kW-month. Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Insufficient Competition will be assessed at the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under this Section III.13.2.8.2.~~

~~III.13.2.9.~~ ~~[Reserved.]~~

III.13.4. Reconfiguration Auctions.

For each Capacity Commitment Period, the ISO shall conduct annual and monthly reconfiguration auctions as described in this Section III.13.4. Reconfiguration auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in reconfiguration auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Sections III.13.4.5 and III.13.4.7) to clear supply offers (i.e., offers to assume a Capacity Supply Obligation) and demand bids (i.e., bids to shed a Capacity Supply Obligation) for each Capacity Zone included in the reconfiguration auction. Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected. Resources that are able to meet the requirements in other Capacity Zones shall be allowed to clear to meet such requirements, subject to the constraints modeled in the auction.

III.13.4.1. Capacity Zones Included in Reconfiguration Auctions.

Each reconfiguration auction associated with a Capacity Commitment Period shall include each of, and only, the final Capacity Zones and external interfaces as determined through the Forward Capacity Auction for that Capacity Commitment Period, as described in Section III.13.2.3.4.

III.13.4.2. Participation in Reconfiguration Auctions.

Each supply offer and demand bid in a reconfiguration auction must be associated with a specific resource, and must satisfy the requirements of this Section III.13.4.2. All resource types may submit supply offers and demand bids in reconfiguration auctions, except Real-Time Emergency Generation Resources which may only submit demand bids. In accordance with Section III.A.9.2 of ***Appendix A*** of this Market Rule 1, supply offers and demand bids submitted for reconfiguration auctions shall not be subject to mitigation by the Internal Market Monitor. A supply offer or demand bid submitted for a reconfiguration auction shall not be limited by the associated resource's Economic Minimum Limit. Offers composed of separate resources may not participate in reconfiguration auctions. Participation in any reconfiguration auction is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of the offer and bid deadline. For annual reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 30 days prior to that deadline. No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 10

Business Days prior to that deadline. Upon issuance of the monthly bilateral results for the associated obligation month, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that monthly auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions in which the most recently approved Winter Seasonal Claimed Capability established as of the fifth Business Day in June of the relevant Capacity Commitment Period is greater than the Winter ARA Qualified Capacity for the third annual reconfiguration auction, the ISO shall apply the greater of these two values to offer limits starting with the first monthly reconfiguration auction in the winter delivery period for the relevant Capacity Commitment Period, limited, as applicable, by the resource's CNR Capability.

III.13.4.2.1. Supply Offers.

Submission of supply offers in reconfiguration auctions shall be governed by this Section III.13.4.2.1. All supply offers in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, in dollars per kW/month. In no case may capacity associated with a Retirement De-List Bid or a Permanent De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that, or any subsequent, Capacity Commitment Period, or any portion thereof. In no case may capacity associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof.

III.13.4.2.1.1. Amount of Capacity That May Be Submitted in a Supply Offer in an Annual Reconfiguration Auction.

For each month of the Capacity Commitment Period associated with the annual reconfiguration auction, the ISO shall calculate the difference between the Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, and the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for the month. The minimum of these 12 values shall be the amount of capacity up to which a resource may submit a supply offer in the annual reconfiguration auction.

III.13.4.2.1.2. Calculation of Summer ARA Qualified Capacity and Winter ARA Qualified Capacity.

III.13.4.2.1.2.1. First Annual Reconfiguration Auction and Second Annual Reconfiguration Auction.

III.13.4.2.1.2.1.1. Generating Capacity Resources Other than Intermittent Power Resources.

III.13.4.2.1.2.1.1.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the higher of the resource's summer Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any summer Seasonal Claimed Capability values for summer periods completed after the Existing Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and where the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.1.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the higher of the resource's winter Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any winter Seasonal Claimed Capability values for winter periods completed after the Existing Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and where the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2. Intermittent Power Resources.

III.13.4.2.1.2.1.2.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined summer Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined winter Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.3. Import Capacity Resources.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to its summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period.

III.13.4.2.1.2.1.4. Demand Resources.

III.13.4.2.1.2.1.4.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined summer Qualified Capacity.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.4.2. Winter ARA Qualified Capacity.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined winter Qualified Capacity.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2. Third Annual Reconfiguration Auction.

III.13.4.2.1.2.2.1. Generating Capacity Resources other than Intermittent Power Resources.

III.13.4.2.1.2.2.1.1. Summer ARA Qualified Capacity.
For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's summer Seasonal Claimed Capability value in effect after the most recently completed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.1(a) shall be zero, however, where the resource cleared in the

Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.1.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2. Intermittent Power Resources.

III.13.4.2.1.2.2.2.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the lesser of its most recently-determined summer Qualified Capacity and its summer Seasonal Claimed Capability value in effect after the most recently competed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the lesser of its most recently-determined winter Qualified Capacity and its winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2.3. Adjustment for Certain Intermittent Power Resources and Intermittent Settlement Only Resources.

For an Intermittent Power Resource or an Intermittent Settlement Only Resource that was not part of an offer composed of separate resources and that has a winter Capacity Supply Obligation that was adjusted as described in Section III.13.2.7.6, if the difference between the resource's winter Capacity Supply Obligation and its Winter ARA Qualified Capacity for the third annual reconfiguration auction is greater than the difference between the resource's summer Capacity Supply Obligation and Summer ARA Qualified Capacity for the third annual reconfiguration auction, then the resource's winter Capacity Supply Obligation shall be reduced such that the difference between the resource's winter Capacity Supply Obligation and its Winter ARA Qualified Capacity for the third annual reconfiguration auction equals the difference between the resource's summer Capacity Supply Obligation and Summer ARA Qualified Capacity for the third annual reconfiguration auction. For settlement purposes, any such reduction in Capacity Supply Obligation 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.13.4.2.1.2.2.3. Import Capacity Resources.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its summer Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import. For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its winter Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import.

III.13.4.2.1.2.2.4. Demand Resources.

III.13.4.2.1.2.2.4.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the lesser of: (i) its most recently-determined summer Qualified Capacity and (ii) its summer Seasonal DR Audit value in effect after the most recently completed summer season or its Demand Resource Commercial Operation Audit performed during the most recently completed summer season, whichever is more recent.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.4.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the lesser of: (i) its most recently-determined winter Qualified Capacity and (ii) its winter Seasonal DR Audit value in effect after the most recently completed winter season or its Demand Resource Commercial Operation Audit performed during the most recently completed winter season, whichever is more recent.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.3. Adjustment for Significant Decreases in Capacity.

For each month of the Capacity Commitment Period associated with the third annual reconfiguration auction, for each resource that has achieved Commercial Operation, the ISO shall subtract the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, from the amount of capacity from the resource that is subject to a Capacity Supply Obligation for the month. For the month associated with the greatest of these 12 values, if the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity (as applicable) is below the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month by more than the lesser of 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or 40 MW, then the following provisions shall apply:

(a) The Lead Market Participant may submit a written plan to the ISO with any necessary supporting documentation describing the measures that will be taken and demonstrating that the resource will be able to provide an amount of capacity consistent with its total Capacity Supply Obligation for the Capacity Commitment Period by the start of all months in that Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If submitted, such a plan must be received by the ISO no later than 10 Business Days after the ISO has notified the Lead Market Participant of its Summer ARA Qualified Capacity and Winter ARA Qualified Capacity for the third annual reconfiguration auction.

(b) If no such plan as described in Section III.13.4.2.1.3(a) is timely submitted to the ISO, or if such a plan is timely submitted but the ISO determines that the plan does not demonstrate that the resource will be able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, then the ISO shall enter a demand bid at the Forward Capacity Auction Starting Price (or, in the case of a resource that cleared in the seventh Forward Capacity Auction, at $12.11/kW-month) on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) in the third annual reconfiguration auction in an amount equal to the greatest of the 12 monthly values determined pursuant to this Section III.13.4.2.1.3.

(c) If the ISO determines that the resource is not able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, and if the resource was part of an offer composed of separate resources when it qualified to participate in the relevant Forward Capacity Auction, then before a demand bid is entered for the resource pursuant to subsection (b) above, the resource may submit monthly Capacity Supply Obligation Bilaterals to cover the deficiency for the months of the Capacity Commitment Period in which the Capacity Supply Obligation is associated with participation in an offer composed of separate resource prior to the third annual reconfiguration auction, but in no case may such a Capacity Supply Obligation Bilateral for a month be for an amount of capacity greater than the difference between the resource’s Capacity Supply Obligation for the month and the resource’s lowest monthly Capacity Supply Obligation during the Capacity Commitment Period.

III.13.4.2.1.4. Amount of Capacity That May Be Submitted in a Supply Offer in a Monthly Reconfiguration Auction.

A resource that has not achieved Commercial Operation by the offer and bid deadline for a monthly reconfiguration auction may not submit a supply offer for that reconfiguration auction, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a supply offer for that reconfiguration auction in an amount up to the absolute value of its Capacity Supply Obligation. The amount of capacity up to which a resource may submit a supply offer in a monthly reconfiguration auction shall be the difference (but in no case less than zero) between (i) the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity as adjusted pursuant to Section III.13.4.2~~,~~, as applicable, for the auction month for the third annual reconfiguration auction for the relevant Capacity Commitment Period; and (ii) the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month. However, a resource may not submit a supply offer for a monthly reconfiguration auction if it is on an approved outage during that month.

III.13.4.2.1.5. ISO Review of Supply Offers.

Supply offers in reconfiguration auctions 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 reviews will consider the location and operating and rating limitations of resources associated with cleared supply offers to ensure reliability standards will remain satisfied if the offer is accepted. The ISO shall reject supply offers that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction. The ISO's reliability reviews will assess such offers, beginning with the marginal resource, 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. Supply offers that cannot meet the applicable reliability needs will be rejected in their entirety and the resource will not be rejected in part. Rejected resources will not be further included in clearing the reconfiguration auction and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.2.2. Demand Bids in Reconfiguration Auctions.

Submission of demand bids in reconfiguration auctions shall be governed by this Section III.13.4.2.2. All demand bids in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the amount of capacity bid in MW, and the price, in dollars per kW/month.

(a) To submit a demand bid in a reconfiguration auction, a resource must have a Capacity Supply Obligation for the Capacity Commitment Period (or portion thereof, as applicable) associated with that reconfiguration auction. Where capacity associated with a Self-Supplied FCA Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period is offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof, a resource acquiring a Capacity Supply Obligation shall not as a result become a Self-Supplied FCA Resource.

(b) Each demand bid submitted to the ISO for reconfiguration auction shall be no greater than the amount of the resource's capacity that is already obligated for the Capacity Commitment Period (or portion thereof, as applicable) as of the offer and bid deadline for the reconfiguration auction.

(c) All demand bids in reconfiguration auctions 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 reviews will consider the location and operating and rating limitations of resources associated with cleared demand bids to ensure reliability standards will remain satisfied if the committed capacity is withdrawn. The ISO shall reject demand bids that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction, provided that for annual reconfiguration auctions associated with a Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall not reject a demand bid solely on the basis that acceptance of the demand bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs). For monthly reconfiguration auctions, the ISO shall obtain and consider information from the Local Control Center regarding whether the capacity associated with demand bids that would otherwise clear from resources with a Capacity Supply Obligation is needed for local system conditions. The ISO's reliability reviews will assess such bids, beginning with the marginal resource, 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. Where the applicable reliability needs cannot be met if a Demand Bid is cleared, such Demand Bids will be rejected in their entirety and the resource will not be rejected in part. Demand Bids from rejected resources will not be further included in clearing the reconfiguration auction, and the Lead

Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.3. ISO Participation in Reconfiguration Auctions.

The ISO shall not submit supply offers or demand bids in monthly reconfiguration auctions. The ISO shall submit supply offers and demand bids in annual reconfiguration auctions as appropriate to address year-to-year changes in the Installed Capacity Requirement (net of HQICCs), Local Sourcing Requirements and Maximum Capacity Limits for the associated Capacity Commitment Period, to procure capacity not purchased in the Forward Capacity Auction as a result of the "Inadequate Supply" rule for Forward Capacity Auctions conducted prior to June 2015, to procure any shortfall in capacity resulting from a resource's achieving Commercial Operation at a level less than that resource's Capacity Supply Obligation or other significant decreases in capacity, and to address any changes in external interface limits, as follows:

(a) For each Capacity Commitment Period that begins on or before June 1, 2017, the ISO shall submit supply offers and demand bids in annual reconfiguration auctions as appropriate to ensure that the applicable Installed Capacity Requirement (net of HQICCs), Local Sourcing Requirements, Maximum Capacity Limits, and external interface limits are respected. Where less capacity than needed is obligated, the ISO shall submit demand bids as appropriate to procure the additional needed capacity in each subsequent annual reconfiguration auction until the need is met. Where more capacity than needed is obligated, the ISO may in its discretion submit supply offers in subsequent annual reconfiguration auctions to release the excess capacity, but in any case the ISO shall be required to submit supply offers as appropriate in the third annual reconfiguration auction for a Capacity Commitment Period to release the excess capacity.

(b) For each Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall submit demand bids for the amount of additional capacity needed to meet the Local Sourcing Requirements and shall submit supply offers in the third annual reconfiguration auction for a Capacity Commitment Period to release capacity exceeding the Maximum Capacity Limits or external interface limits.

(c) No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall provide notice regarding whether the ISO will be submitting supply offers or demand bids in that auction.

(d) Any demand bid submitted by the ISO in an annual reconfiguration auction shall be at the Forward Capacity Auction Starting Price, except for any demand bids submitted by the ISO in annual reconfiguration auctions associated with the seventh Capacity Commitment Period, which shall be at $12.11/kW-month.

(e) Any supply offer submitted by the ISO in an annual reconfiguration auction shall be in the form of a supply curve having the following characteristics:

(i) at prices equal to or greater than 0.75 times the Capacity Clearing Price, as adjusted pursuant to Section III.13.2.7.3(b), from the Forward Capacity Auction for the Capacity Commitment Period covered by the annual reconfiguration auction, the ISO shall offer the full amount of the surplus;

(ii) at prices between 0.75 times such Capacity Clearing Price and 0.25 times such Capacity Clearing Price, the amount of the surplus offered by the ISO shall decrease linearly (for example, at 0.5 times such Capacity Clearing Price, the ISO shall offer half of the amount of the surplus); and

(iii) At prices equal to or below 0.25 times such Capacity Clearing Price, the ISO shall offer no capacity.

(f) For purposes of this Section III.13.4.3, the Forward Capacity Auction Starting Price shall be the Forward Capacity Auction Starting Price associated with the Forward Capacity Auction for the same Capacity Commitment Period addressed by the reconfiguration auction, as determined pursuant to Section III.13.2.4.

(g) Supply offers and demand bids submitted by the ISO in annual reconfiguration auctions are not subject to the requirements and limitations described in Section III.13.4.2.

(h) Supply offers and demand bids submitted by the ISO in annual reconfiguration auctions are not associated with a resource.

III.13.4.4. Clearing Offers and Bids in Reconfiguration Auctions.

All supply offers and demand bids may be cleared in whole or in part in all reconfiguration auctions. If after clearing, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.4.5. Annual Reconfiguration Auctions.

Except as provided below, after the Forward Capacity Auction for a Capacity Commitment Period, and before the start of that Capacity Commitment Period, the ISO shall conduct three annual reconfiguration auctions for capacity commitments covering the whole of that Capacity Commitment Period. For each annual reconfiguration auction, the capacity demand curves, New England Control Area and Capacity Zone capacity requirements and external interface limits, as updated pursuant to Section III.12, shall be modeled ~~as constraints~~ in the auction consistent with the Forward Capacity Auction for the associated Capacity Commitment Period. For purposes of the annual reconfiguration auctions, the Forward Capacity Auction Starting Price used to define the System-Wide Capacity Demand Curve shall be the Forward Capacity Auction Starting Price associated with the Forward Capacity Auction for the same Capacity Commitment Period addressed by the reconfiguration auction.

III.13.4.5.1. Timing of Annual Reconfiguration Auctions.

Except for the first five Capacity Commitment Periods, the first annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of June that is approximately 24 months before the start of the Capacity Commitment Period. The second annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of August that is approximately 10 months before the start of the Capacity Commitment Period. The third annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of March that is approximately 3 months before the start of the Capacity Commitment Period. There shall be no first annual reconfiguration auction for the first five Capacity Commitment Periods. The table below illustrates the annual reconfiguration auction timing provisions stated above, providing the schedule of annual reconfiguration auctions for the first eight Capacity Commitment Periods.

First Annual Reconfiguration Auction	Second Annual Reconfiguration	Third Annual Reconfiguration	Capacity Commitment Period Begins
N/A	May 2009	March 2010	June 1, 2010
N/A	May 2010	March 2011	June 1, 2011
N/A	May 2011	March 2012	June 1, 2012
N/A	May 2012	March 2013	June 1, 2013
N/A	August 2013	March 2014	June 1, 2014
June 2013	August 2014	March 2015	June 1, 2015
June 2014	August 2015	March 2016	June 1, 2016
June 2015	August 2016	March 2017	June 1, 2017

III.13.4.5.2. Acceleration of Annual Reconfiguration Auction.

If the difference between the forecasted Installed Capacity Requirement (net of HQICCs) for a Capacity Commitment Period and the amount of capacity obligated for that Capacity Commitment Period is sufficiently large, then the ISO may, upon reasonable notice to Market Participants, conduct an annual reconfiguration auction as much as six months earlier than its normally-scheduled time.

III.13.4.6. [Reserved.]

III.13.4.7. Monthly Reconfiguration Auctions.

Prior to each month in the Capacity Commitment Period, the ISO shall conduct a monthly reconfiguration auction for whole-month capacity commitments during that month. For each monthly reconfiguration auction, the Local Sourcing Requirement and Maximum Capacity Limit applicable for each Capacity Zone and external interface limits, as updated pursuant to Section III.12, shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in monthly reconfiguration auctions.

III.13.4.8. Adjustment to Capacity Supply Obligations.

For each supply offer that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be increased by the amount of capacity that clears. For each demand bid that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be decreased by the amount of capacity that clears.

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 or reduced by the resource's capacity obligation in an adjacent Control Area assigned to an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented).

(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 or reduced by the resource's capacity obligation in an adjacent Control Area assigned to an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented, when a Market Participant notifies the ISO, in accordance with the ISO's annual maintenance scheduling process, that an asset associated with the External Resource is on an outage that was approved in the resource's native Control Area. 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 provisions of this Section III.13.7.1.2 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

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). 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.1.3.7.1.2.A. Import Capacity on External Interfaces with Enhanced Scheduling.

The following available MW determination applies to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1. The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as designed 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.A.1). The available MW in each hour that contains any portion of a Shortage Event shall be determined as follows:

(a) If the native Control Area delivers the total requested MW of Import Capacity Resources, or more than the total requested MW, then the available MW of a resource within that Control Area will be its Capacity Supply Obligation in the interval when the ISO requested delivery.

(b) If the native Control Area delivers less than the total requested MW of Import Capacity Resources, then the available MW of a resource within that Control Area in the interval when the ISO requested delivery and that contains any portion of a Shortage Event shall be established as follows:

(i) The quantity available is zero if the resource is offline in the native Control Area for the interval when the ISO requested delivery;

(ii) The quantity available is the maximum output available from the resource, as reflected in the resource's offer data, adjusted for any non-New England capacity obligation to which the resource is subject if the resource is online in the native Control Area for the interval when the ISO requested delivery.

(c) If the ISO does not request MW of Import Capacity Resources, then the available MW of a resource within that Control Area will be its Capacity Supply Obligation.

III.13.7.1.2.A.1. Availability Adjustments.

When the available MW of an Import Capacity Resource is calculated under Section III.13.7.1.2.A(b), the hourly availability score of any such Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource has complied with the provisions in Section III.13.7.1.1.4(b) for outage scheduling.

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 Resouce 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 Resouce 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)~~ (or, if applicable, the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015) 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 six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

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 $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-List Bid]
>
> Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.3.1.

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, 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:

Hourly PER($/kW) = [(LMP - Strike Price) * [Scaling Factor] * [Availability Factor]

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand 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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to “Inadequate Supply” or “Insufficient Competition”) that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015~~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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to “Inadequate Supply” or “Insufficient Competition”) that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015~~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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to “Inadequate Supply” or “Insufficient Competition”) that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015, ~~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 provisions in (a) and (b) below. In addition, all Import Capacity Resources will be subject to the provisions in (c) below.

(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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015~~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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015~~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).

(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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015~~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 submitted under Section III.1.10.7 and 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.

For Import Capacity Resources with a Capacity Obligation at an external interface for which the enhanced scheduled procedures in Section III.1.10.7.A are implemented (unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.), the requested and delivered MW are determined as follows:

(i) If the native Control Area delivers the total requested MW of Import Capacity Resources, or more than the total requested MW, then the resources within that Control Area will not be evaluated for penalties.

(ii) If the native Control Area delivers less than the total requested MW of Import Capacity Resources, then the resources will be evaluated using the following requested and delivered MW values:

1. The quantity requested is the resource's Capacity Supply Obligation; and
2. The quantity delivered for a resource is determined as follows:

a. The quantity delivered is zero if the resource is offline in the native Control Area for the interval when the ISO requested delivery;

b. The quantity delivered is the maximum output available from the resource, as reflected in the resource's offer data, adjusted for any non-New England capacity obligation to which the resource is subject if the resource is online in the native Control Area for the interval when the ISO requested deliver;

c. For purposes of this determination, the total energy delivered will be adjusted in accordance with Section III.13.7.1.1.4(b).

(iii) If the ISO does not request MW of Import Capacity Resources, then the resources within that Control Area will not be evaluated for delivery penalties.

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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015~~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.

The exceptions in Sections III.13.7.2.7.2.2.b, c and d do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduled procedures in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

a) No penalty will be assessed if the applicable external interface is fully loaded in the import direction. 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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015~~ 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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015~~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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015~~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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015~~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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015~~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, if applicable, minus the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015~~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.

III.13.8. Reporting and Price Finality

III.13.8.1. Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto.

(a) For each Forward Capacity Auction, no later than 20 Business Days after the issuance of retirement determination notifications described in Section III.13.1.2.4(a), the ISO shall make a filing with the Commission pursuant to Section 205 of the Federal Power Act describing the Permanent De-List Bids and Retirement De-List Bids. The ISO will file the following information confidentially: the determinations made by the Internal Market Monitor with respect to each Permanent De-List Bid and Retirement De-List Bid, and supporting documentation for each such determination. The confidential filing shall indicate those resources that will permanently de-list or retire prior to the Forward Capacity Auction and those Permanent De-List Bids and Retirement De-List Bids for which a Lead Market Participant has made an election pursuant to Section III.13.1.2.4.1.

(b) The Forward Capacity Auction shall be conducted using the determinations as approved by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

(c) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), and (viii) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), and (viii) shall be published by the ISO no later than 15 days after the Forward Capacity Auction) , with the excepetion of de-list bid price information, which shall remain confidential):

(i) which Capacity Zones shall be modeled in the Forward Capacity Auction;

(ii) the transmission interface limits as determined pursuant to Section III.12.5;

(iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

(iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;

(v) the multipliers applied in determining the Capacity Value of a Demand Resource, as described in Section III.13.7.1.5.1;

(vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;

(vii) the Internal Market Monitor's determinations regarding each requested offer price from a new resource submitted pursuant to Section III.13.1.1.2.2.3 or Section III.13.1.4.2, including information regarding each of the elements considered in the Internal Market Monitor's determination of expected net revenues (other than revenues from ISO-administered markets) and whether that element was included or excluded in the determination of whether the offer is consistent with the resource's long run average costs net of expected net revenues other than capacity revenues;

(viii) the Internal Market Monitor's determinations regarding offers or Static De-List Bids, Export Bids, and Administrative De-List Bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the Internal Market Monitor-determined prices established for any Static De-List Bids, Export Bids, and Administrative De-List Bids as described in Section III.13.1.2.3.2 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. The filing shall identify to the extent possible the components of the bid which were accepted as justified, and shall also identify to the extent possible the components of the bid which were not justified and which resulted in the Internal Market Monitor establishing an Internal Market Monitor-determined price for the bid;

(ix) which existing resources are qualified to participate in the Forward Capacity Auction (this information will include resource type, capacity zone, and qualified MW); and

(x) aggregate MW from new resources qualified to participate in the Forward Capacity Auction and aggregate de-list bid amounts.

(d) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(c) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4(b) and III.13.1.3.5.7 must be filed with the Commission no later than 15 days after the ISO's submission of the informational filing. If the Commission does not issue an order within 75 days after the ISO's submission of the informational filing that directs otherwise, the determinations contained in the informational filing shall be used in conducting the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within 75 days after the ISO's submission of the informational filing, the Commission does issue an order modifying one or more of the ISO's determinations, then the Forward Capacity Auction shall be conducted no earlier than 15 days following that order using the determinations as modified by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Facility, as defined in Schedule 22 or Schedule 25 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity

Auction subject to a Long Lead Time Facility with the higher queue priority. The filing shall also enumerate bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.

(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO's filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.

(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.

~~**III.13.8.3. [Reserved.]**~~

~~**III.13.8.4. [Reserved.]**~~

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

Table of Contents

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this ***Appendix A.***

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this ***Appendix A*** shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this ***Appendix A***. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market

Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***. This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III. A.17.3 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this ***Appendix A*** are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this ***Appendix A***). In the event the Internal Market Monitor or External Market

Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

(b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.

(c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the External Market Monitor shall perform the following functions:

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(c) Conduct evaluations and prepare reports on its own initiative or at the request of others.

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this ***Appendix A***.

(f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.

(g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this ***Appendix A***, as appropriate.

(h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the Internal Market Monitor shall perform the following functions:

(a) Maintain ***Appendix A*** and consider whether ***Appendix A*** requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.

(b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this ***Appendix A***.

(c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this ***Appendix A.***

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

(i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this ***Appendix A***.

(j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this ***Appendix A*** are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

(i) *Economic withholding,* that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.

(ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.

(iii) *Anti-competitive Increment Offers and Decrement Bids,* which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids,* which are addressed in Section III.A.10 of this ***Appendix A.***

(v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend ***Appendix A*** as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

(i) Anti-competitive gaming of Resources;

(ii) Conduct and market outcomes that are inconsistent with competitive markets;

(iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;

(iv) Actions in one market that affect price in another market;

(v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this ***Appendix A***, interfere with efficient market operation, both short-run and long-run; and

(vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this ***Appendix A***. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

(m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with ***Appendix B*** of this Market Rule l.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this ***Appendix A*** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule l (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this ***Appendix A***. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this ***Appendix A***, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under ***Appendix B*** of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

(a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:

(b) Notwithstanding the foregoing or any other provision of this ***Appendix A***, and as more fully described in Section III.B.3.2.6 of ***Appendix B*** to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. **Applicability.**

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. **Mitigation Not Provided for Under This *Appendix A*.**

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this ***Appendix A***, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. **Duration of Mitigation.**

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this ***Appendix A*** or in ***Appendix B*** to this Market Rule 1.

III.A.3. **Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.**

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant**.** In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective.

Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(c) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this ***Appendix A*** for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus $2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2
2 or more	6

III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,

(b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,

(c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or

(d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

(a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;

(b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding;

(b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;

(c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 “Constrained Area Energy Mitigation” and Section III.A.5.5.5 “Constrained Area Commitment Mitigation” apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

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III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

(a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;

(b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource’s Node exceeds the LMP at the Hub by more than $25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 “Constrained Area Energy Mitigation” is equal to the difference between the LMP at the Resource’s Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

(a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;

(b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or $100/MWh, whichever is lower. Offer block prices below $25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or $100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or $25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or $25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

i. local first contingency;
ii. local second contingency;
iii. VAR or voltage;
iv. distribution (Special Constraint Resource Service);
v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

(a) If the Resource is starting from an offline state, the Start-Up Fee;
(b) The sum of the No Load Fees for the Commitment Period; and
(c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 "General Threshold Energy Mitigation" or III.A.5.5.2 "Constrained Area Energy Mitigation" is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

  i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,

  ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 "Constrained Area Energy Mitigation"), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 "Manual Dispatch Energy Mitigation" is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource's Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 "General Threshold Commitment Mitigation", III.A.5.5.5 "Constrained Area Commitment Mitigation", or III.A.5.5.6 "Reliability Commitment Mitigation" is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 "Start-Up Fee and No-Load Fee Mitigation" is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

(a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.
(b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.
(c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Supply Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of a Supply Offer according to the following hierarchy, under which the first method that can be calculated is used:

(a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;

(b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,

(c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

(a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.

(b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.

(c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.

(d) For any Operating Day for which, during the previous 90 days:

(i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;

(ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.

(iii) The Market Participant submits a fuel price pursuant to Section III.A.3.4.

For the purposes of this subsection:

i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.

ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.

iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

(e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.

(f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:

(i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,

(ii) No-Load Fee or its corresponding fuel blends,

(iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,

(iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and

(v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

(a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".
(b) Costs must be documented.
(c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible.
(d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.
(e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be

calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

i. Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and
ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy:
(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

(a) emissions limits;
(b) water storage limits; and,
(c) other operating permits that limit production of energy.

No-Load:
(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up:
(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. Determination of Offer Competitiveness During Shortage Event.

The Internal Market Monitor shall evaluate the competitiveness of the Supply Offer of each Resource with a Capacity Supply Obligation that is off-line during a Shortage Event, as described below. The evaluation for competitiveness shall be performed on Supply Offers in the Day-Ahead Energy Market and on Supply Offers in the Real-Time Energy Market. For purposes of these evaluations, Reference Levels are calculated using the cost-based method specified in Section III.A.7.5. The Real-Time Energy Market evaluation uses the final Supply Offer in place for the hour.

(a) Hours Evaluated. For Supply Offers in the Day-Ahead Energy Market, competitiveness is evaluated for all hours of the Operating Day during which a Shortage Event occurs. For Supply Offers in the Real-Time Energy Market competitiveness is evaluated for the last hour that the Resource could have been committed to be online at its Economic Minimum Limit at the start of the Shortage Event, taking into account the Resource's Start-Up Time and Notification Time.

(b) Competitiveness Evaluation of Energy Offer At Low Load.

  (i) If the Resource is not in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

  (ii) If the Resource is in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

(c) Competitiveness Evaluation of Energy Offer Above Low Load. If a Supply Offer evaluated for competitiveness pursuant to Section III.A.8 (b) above is competitive for an hour, then the energy price parameter for each incremental Supply Offer block above the Resource's Economic Minimum Limit shall be evaluated for competitiveness using the thresholds identified in Section III.A.5.5.1.2, for Resources not in a constrained area, and the thresholds identified in Section III.A.5.5.2.2, for Resources in a constrained area, in order of lowest energy price to highest energy price. If any Supply Offer block is non-competitive, then that block and all blocks above it shall be non-competitive, and all blocks below it shall be competitive.

(d) Low Load Cost test. Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit for its Minimum Run Time, is calculated as the sum of:

  i. The Start-Up Fee (cold start);

  ii. The sum of the No Load Fees for the Resource's Minimum Run Time; and

iii. The sum of the hourly values resulting from the multiplication of the price of energy at the Resource’s Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Resource’s Minimum Run Time.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource’s Supply Offer at the Economic Minimum Limit offer Block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource’s Reference Level at the Economic Minimum Limit offer Block.

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor’s justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor Demand Resources as outlined below:

(a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.

(b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1.$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

(i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.

(ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.

(iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

(a) [Reserved].
(b) Section III.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.
(c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

(d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.
(e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.
(f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this ***Appendix A***. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed

Documents and other ISO New England System Rules. The Internal Market Monitor shall administer ***Appendix B*** in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.
Article 5 of the form of Cost-of-Service Agreement in ***Appendix I*** to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Filing Right.
If either

(a) as a result of mitigation applied to a Resource under this ***Appendix A*** for all or part of one or more Operating Days, or

(b) in the absence of mitigation, despite having submitted a Supply Offer at the Energy Offer Cap,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for the hours of the Operating Day during which the Supply Offer was mitigated or during which the Resource was operated at the Energy Offer Cap, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having submitted a Supply Offer at the Energy Offer Cap, costs incurred for the duration of the period of time for which the Resource was operated at the Energy Offer Cap.

III.A.15.2. Contents of Filing.
Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data

and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource exceeded the costs as reflected in the Supply Offer at the Energy Offer Cap; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.

III.A.15.4. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in ***Appendix D*** to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.

- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this ***Appendix A***, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

(a) the opportunity costs associated with Demand Reduction Offers;

(b) the accuracy of Demand Response Baselines;

(c) the method used to achieve a demand reduction, and;

(d) the accuracy of reported demand levels.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A.***

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this ***Appendix A***.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of ***Appendix A***. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

(i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.

(ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.

(iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.

(iv) Review and assessment of the effectiveness of ***Appendix A*** and the administration of ***Appendix A*** by the Internal Market Monitor for consistency and compliance with the terms of ***Appendix A.***

(v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;

(b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;

(c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). With respect to state regulatory bodies and state attorneys general ("authorized state agencies"), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as ***Exhibit 5***.

III.A.18.2. Additional Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of ***Appendix A***, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the

Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information

(1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);

(2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;

(3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

(4) The specific act(s) or conduct that allegedly constituted the Market Violation;

(5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

(6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;

(7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) A detailed narrative describing the perceived market design flaw(s);

(2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;

(3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;

(4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.2.4 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Ninth Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018) shall be as follows:

Generation Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
combustion turbine	$13.424
combined cycle gas turbine	$8.866
on-shore wind	$10.320

Demand Resources - Commercial and Industrial	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management and/or previously installed Distributed Generation	$1.145
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Demand Resources – Residential	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management	$7.094

previously installed Distributed Generation	$1.145
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Other Resources

All other technology types	Forward Capacity Auction Starting Price

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

For purposes of determining the Offer Review Trigger Price of a Demand Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the new Demand Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

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

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

(c) For new Demand Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for new generation resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For new Demand Resources other than Demand Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for new generation resources, except that the model discounts cash flows over the contract life. For Demand Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Resources (other than Demand Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"
steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS “Quarterly Census of Employment and Wages” 2371 Utility System Construction Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
other labor	BLS “Quarterly Census of Employment and Wages” 2211 Power Generation and Supply Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)”
fuel inventories	Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
labor, administrative and general	BLS “Quarterly Census of Employment and Wages” 2211 Power Generation and Supply Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit

	Price Deflator (GDPDEF)"

(3) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the ninth FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the ninth FCA will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices from the time of the update through the end of the Capacity Commitment Period associated with the relevant FCA, and the Massachusetts Hub On-Peak electricity prices and the Algonquin City Gates natural gas prices for the 12 months following the time of the update, as published by the CME Group.

(5) Renewable energy credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.2.4, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.2.4, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a new Demand Resource, the resource's costs shall
include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred by the Demand Response provider and end-use customers to acquire the Demand Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the Demand Resource, and expected costs avoided by the end-use customer as a direct result of the installation or implementation of the Demand Resource.

(iii) For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in

Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

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

III.A.21.3. Special Treatment of Certain Out-of-Market Capacity Resources in the Eighth Forward Capacity Auction.

For the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017), the provisions of Sections III.A.21.1 and III.A.21.2 shall also apply to certain resources that cleared in the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2015) and/or the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2016), as follows:

(a) This Section III.A.21.3 shall apply to: (i) any capacity clearing in the sixth or seventh Forward Capacity Auction as a New Generating Capacity Resource or New Import Capacity Resource designated as a Self-Supplied FCA Resource; and (ii) any capacity clearing in the sixth or seventh Forward Capacity Auction from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at prices found by the Internal Market Monitor to be not consistent with either: (a) the resource's long run average costs net of expected net revenues other than capacity revenues for a New Generating Capacity Resource and a New Demand Resource or (b) opportunity costs for a New Import Capacity Resource.

(b) For the eighth Forward Capacity Auction, the capacity described in subsection (a) above shall receive Offer Review Trigger Prices as described in Section III.A.21.1 and New Resource Offer Floor Prices as described in Section III.A.21.2. These values will apply to such capacity in the conduct of the eighth Forward Capacity Auction as described in Section III.13.2.3.2.

(c) For the eighth Forward Capacity Auction, the Project Sponsor or Lead Market Participant for such capacity may be required to comply with some or all of the qualification provisions applicable to new resources described in Section III.13.1. These requirements will be determined by the ISO on a case-by-case basis in consultation with the Project Sponsor or Lead Market Participant.

(d) For any capacity described in subsection (a) above that does not clear in the eighth Forward Capacity Auction:

(i) any prior election to have a Capacity Clearing Price and Capacity Supply Obligation continue to apply for more than one Capacity Commitment Period made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 shall be terminated as of the beginning of the Capacity Commitment Period associated with the eighth FCA (beginning June 1, 2017); and

(ii) after the eighth Forward Capacity Auction, such capacity will be deemed to have never been previously counted as capacity, such that it meets the definition, and must meet the requirements, of a new capacity resource for the subsequent Forward Capacity Auction in which it seeks to participate.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources in the Rest-of-Pool Capacity Zone;
(b) For each modeled import-constrained Capacity Zone, the greater of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
(c) For each modeled export-constrained Capacity Zone, the lesser of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the export-constrained Capacity Zone plus, for each external interface connected to the export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Maximum Capacity Limit of the export-constrained Capacity Zone, and;
(d) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(e) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources located within the import-constrained Capacity Zone; and

(f) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.

(b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import

Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

**III.A.24.	Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.**

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than

ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

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.

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 costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

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

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

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

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

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.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

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

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

Category 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 the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

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

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

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

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

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

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

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

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

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

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

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

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

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.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.
Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

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

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

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

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

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

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

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, 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.

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

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

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

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

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(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 (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points and meets the criteria specified in Section III.1.11.3(e).

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator 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 for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, 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 Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

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

Existing Demand 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.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

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

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

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

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

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to

Dispatch Instructions or has automatic remote response capability; (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.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; and (iv) has satisfied its Minimum Down Time.

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 $9,000/megawatt-month.

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

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

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

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

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

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

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

FTR 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.

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.

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.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

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.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

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

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.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

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

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

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

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

Limited Energy Resource means 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.

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.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

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

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

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

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

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

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

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

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

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

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

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

Maximum Capacity Limit is 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 over-stated 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 (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

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

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

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

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

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

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

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

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.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

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

MW is megawatt.

MWh is megawatt-hour.

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

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

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

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

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

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

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

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

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

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

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

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 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; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

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

Non-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-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.13.1.2.3.1.5 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

Point(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.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a 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 costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

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

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

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

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.

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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

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III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

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

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

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

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

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

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

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

III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction. The Local Sourcing Requirement shall represent the minimum amount of capacity that must be procured within an import-constrained Capacity Zone. The Maximum Capacity Limit shall represent the maximum amount of capacity that can be procured in an export-constrained Capacity Zone to meet the Installed Capacity Requirement.

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

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

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

III.12.2.1.1. Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

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

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

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

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

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

In which:

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

Proxy Units

Adjustment	=	MW of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1 days/year.

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

III.12.2.1.2. Transmission Security Analysis Requirement.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

In which:

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

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

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

III.12.2.2.1. Marginal Reliability Impact Values for Export-Constrained Capacity Zones.

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

III.12.3 Consultation and Filing of Capacity Requirements.

At least two months prior to filing the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves with the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act 90 days prior to the Forward Capacity Auction for the Capacity Commitment Period. The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given FCA, any new Capacity Zone must have received approval from the Commission prior to the Existing Capacity Qualification Deadline of the applicable FCA.

III.12.4. Capacity Zones.

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

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

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

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

III.12.5. Transmission Interface Limits.

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

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

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

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

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

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

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

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

III.12.6.1. Process for Establishing the Network Model.

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

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

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

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

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

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

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

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

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

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

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

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

III.12.6.3. Evaluation Criteria.

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

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

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

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

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

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

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

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

III.12.7. Resource Modeling Assumptions.

III.12.7.1. Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as additional capacity to determine the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all other resources in the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

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

III.12.7.2. Capacity.

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

(a) all Existing Generating Capacity Resources,

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

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

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

but shall exclude:

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

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

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

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

III.12.7.2.1. [Reserved.]

III.12.7.3. Resource Availability.

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

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The most recent five-year moving average of EFORd shall be used as the measure of resource availability for non-peaking resources used in the calculation of Transmission Security Analysis Requirements. A deterministic adjustment factor, based on the operational experience of the ISO, shall be used as the measure of resource availability for peaking resources used in the calculation of Transmission Security Analysis Requirements, and will be reviewed periodically.

(b) [Reserved.]

(c) Once sufficient data are collected under the availability incentives in the Forward Capacity Market, a resource availability metric, which reflects resource availability in a manner that is consistent with the availability incentives in the Forward Capacity Market, shall be developed and reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies and used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

For resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that do not have sufficient data to calculate an availability metric as defined in subsections (a) or (c) above, class average data for similar resource types shall be used. For Demand Resources, including Real-Time Emergency Generation, historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

III.12.7.4. Load and Capacity Relief.

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

(a) **Implement voltage reduction**. The MW value of the load relief shall be equal to the percentage load reduction achieved in the most applicable voltage reduction tests multiplied by the forecasted seasonal peak loads.

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

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

III.12.8. Load Modeling Assumptions.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias. Demand Resources shall be reflected in the load forecast as specified below:

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

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

(c) [Reserved.]

(d) Any realized Demand Resource reductions in the historical period that received Forward Capacity Market payments for these reductions, or Demand Resource reductions that are expected to receive Forward Capacity Market payments by participating in the upcoming Forward Capacity Auction or having cleared in a previous Forward Capacity Auction, shall be added back into the appropriate historical loads to ensure that such resources are not reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period.

III.12.9. Tie Benefits.

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

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

III.12.9.1. Overview of Tie Benefits Calculation Procedure.

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

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

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

III.12.9.1.2. Tie Benefits Calculation.

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

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

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

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

III.12.9.2.1. Assumptions Regarding System Conditions.

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

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

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

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

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

III.12.9.2.4. Other Modeling Assumptions.

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

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

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

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

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

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

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

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

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

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

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

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

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

III.12.9.3. Calculating Total Tie Benefits.

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

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

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

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

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

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

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

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

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

III.12.9.5. Calculating Tie Benefits for Individual Ties.

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

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

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

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

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

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

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

III.12.9.6.1. Accounting for Capacity Imports.

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

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

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

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

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

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

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

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

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

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

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

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

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

(iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

(1) at prices above $7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;

(2) at prices below $7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between $7.03/kW-month and $0.00/kW-month and determined by the following quantities:
   (a) At the price of $0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.
   (b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at $7.03/kW-month, the quantity shall be the lesser of:
      1. 35,437 MW; and
      2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;
   (c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at $7.03/kW-month, the quantity shall be the lesser of:
      1. 35,090 MW; and
      2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;
   (d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at $7.03/kW-month, the quantity shall be the lesser of:
      1. 34,865 MW; and
      2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month

(3) a price of $7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p)=\begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \le p_1, \\ q_2, & \text{if } p_3 < p \le p_2, \\ \dots & \dots \quad , \\ q_m, & \text{if } p \le p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic Delist Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be bid into the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to

Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 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 a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

(1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:

  (i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits), or;

  (ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;

(4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:

  (i) that interface's approved capacity transfer limit (net of tie benefits), or;

  (ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then the auctioneer shall publish the quantity of capacity in the Capacity Zone from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**.

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price, and also shall publish the quantity of capacity from Demand Resources by type at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones**. For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

(1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero, and;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the export-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and the quantity of capacity in the Capacity Zone from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-

TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

(f) **Treatment of Real-Time Emergency Generation Resources.** In determining when the Forward Capacity Auction is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation Resources shall be counted towards meeting the cleared amount of capacity determined by the System-Wide Capacity Demand Curve. If the sum of the Capacity Supply Obligations of Real-Time Emergency Generation Resources exceeds 600 MW, the Capacity Clearing Price, or, if applicable, the administratively-determined payment rate (due to “Inadequate Supply” or “Insufficient Competition”) that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015, paid to all Real-Time Emergency Generation Resources shall be adjusted by the ratio of 600 MW divided by the total of the final Capacity Supply Obligations of Real-Time Emergency Generation Resources. A Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, Permanent De-list Bid, or Retirement De-List Bid shall clear based on the effective Capacity Clearing Price as described in Section III.13.2.7.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2018 is $14.04/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2018 is $11.08/kW-month.

CONE and Net CONE shall be recalculated using updated data coincident with the recalculation of Offer Review Trigger Prices pursuant to Section III.A.21.1.2. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e), except that the energy and ancillary services offset will be adjusted using publicly available data for Mass Hub On-Peak electricity futures through the commitment period of the FCA and will not be adjusted based on natural gas prices. Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the bid has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated if either of the following conditions is met in the initial auction clearing process: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation); or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation) and the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price. The second run of the auction-clearing process: (i) excludes all Proxy De-List Bid(s), (ii) includes the offers and bids of resources that did not receive a Capacity Supply Obligation in the first run of the auction-clearing process, and (iii) includes the capacity of resources, or portion thereof, that received a Capacity Supply Obligation in the first run of the auction-clearing process. The second run of the auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) that receive a Capacity Supply Obligation as a result of the first run of the auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource’s Economic Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. Reliability Review.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid to determine whether the capacity associated with that de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station.. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. De-list bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) Where a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction.

(c) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject the de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability. Resources that submitted Permanent De-List Bids or Retirement De-List Bids shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii)).

(g) If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1.

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability

Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the "just and reasonable" standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity

Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the Capacity Commitment Period for which the Retirement De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: submitted a Retirement De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III.13.1.2.3.1.5(d); elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction; or, for a resource, or portion thereof, that submitted a Permanent De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the Capacity Commitment Period for which its Permanent De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: submitted a Permanent De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III. III.13.1.2.3.1.5(d); was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export

Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for each import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. Capacity Clearing Price Floor.

In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below $3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches $3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to $3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.

(ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).

(iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource’s payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply 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 Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5.

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) [Reserved.]

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources) shall be cleared.

III.13.4. Reconfiguration Auctions.

For each Capacity Commitment Period, the ISO shall conduct annual and monthly reconfiguration auctions as described in this Section III.13.4. Reconfiguration auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in reconfiguration auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Sections III.13.4.5 and III.13.4.7) to clear supply offers (i.e., offers to assume a Capacity Supply Obligation) and demand bids (i.e., bids to shed a Capacity Supply Obligation) for each Capacity Zone included in the reconfiguration auction. Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected. Resources that are able to meet the requirements in other Capacity Zones shall be allowed to clear to meet such requirements, subject to the constraints modeled in the auction.

III.13.4.1. Capacity Zones Included in Reconfiguration Auctions.

Each reconfiguration auction associated with a Capacity Commitment Period shall include each of, and only, the final Capacity Zones and external interfaces as determined through the Forward Capacity Auction for that Capacity Commitment Period, as described in Section III.13.2.3.4.

III.13.4.2. Participation in Reconfiguration Auctions.

Each supply offer and demand bid in a reconfiguration auction must be associated with a specific resource, and must satisfy the requirements of this Section III.13.4.2. All resource types may submit supply offers and demand bids in reconfiguration auctions, except Real-Time Emergency Generation Resources which may only submit demand bids. In accordance with Section III.A.9.2 of ***Appendix A*** of this Market Rule 1, supply offers and demand bids submitted for reconfiguration auctions shall not be subject to mitigation by the Internal Market Monitor. A supply offer or demand bid submitted for a reconfiguration auction shall not be limited by the associated resource's Economic Minimum Limit. Offers composed of separate resources may not participate in reconfiguration auctions. Participation in any reconfiguration auction is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of the offer and bid deadline. For annual reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 30 days prior to that deadline. No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 10

Business Days prior to that deadline. Upon issuance of the monthly bilateral results for the associated obligation month, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that monthly auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions in which the most recently approved Winter Seasonal Claimed Capability established as of the fifth Business Day in June of the relevant Capacity Commitment Period is greater than the Winter ARA Qualified Capacity for the third annual reconfiguration auction, the ISO shall apply the greater of these two values to offer limits starting with the first monthly reconfiguration auction in the winter delivery period for the relevant Capacity Commitment Period, limited, as applicable, by the resource's CNR Capability.

III.13.4.2.1. Supply Offers.

Submission of supply offers in reconfiguration auctions shall be governed by this Section III.13.4.2.1. All supply offers in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, in dollars per kW/month. In no case may capacity associated with a Retirement De-List Bid or a Permanent De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that, or any subsequent, Capacity Commitment Period, or any portion thereof. In no case may capacity associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof.

III.13.4.2.1.1. Amount of Capacity That May Be Submitted in a Supply Offer in an Annual Reconfiguration Auction.

For each month of the Capacity Commitment Period associated with the annual reconfiguration auction, the ISO shall calculate the difference between the Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, and the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for the month. The minimum of these 12 values shall be the amount of capacity up to which a resource may submit a supply offer in the annual reconfiguration auction.

III.13.4.2.1.2. Calculation of Summer ARA Qualified Capacity and Winter ARA Qualified Capacity.

III.13.4.2.1.2.1. First Annual Reconfiguration Auction and Second Annual Reconfiguration Auction.

III.13.4.2.1.2.1.1. Generating Capacity Resources Other than Intermittent Power Resources.

III.13.4.2.1.2.1.1.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the higher of the resource's summer Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any summer Seasonal Claimed Capability values for summer periods completed after the Existing Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and where the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.1.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the higher of the resource's winter Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any winter Seasonal Claimed Capability values for winter periods completed after the Existing Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and where the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2. Intermittent Power Resources.

III.13.4.2.1.2.1.2.1. Summer ARA Qualified Capacity.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined summer Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined winter Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.3. Import Capacity Resources.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to its summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period.

III.13.4.2.1.2.1.4. Demand Resources.

III.13.4.2.1.2.1.4.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined summer Qualified Capacity.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.4.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the resource's most recently-determined winter Qualified Capacity.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2. Third Annual Reconfiguration Auction.

III.13.4.2.1.2.2.1. Generating Capacity Resources other than Intermittent Power Resources.

III.13.4.2.1.2.2.1.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's summer Seasonal Claimed Capability value in effect after the most recently completed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.1(a) shall be zero, however, where the resource cleared in the

Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.1.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource's winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2. Intermittent Power Resources.

III.13.4.2.1.2.2.2.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the lesser of its most recently-determined summer Qualified Capacity and its summer Seasonal Claimed Capability value in effect after the most recently competed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the lesser of its most recently-determined winter Qualified Capacity and its winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2.3. Adjustment for Certain Intermittent Power Resources and Intermittent Settlement Only Resources.

For an Intermittent Power Resource or an Intermittent Settlement Only Resource that was not part of an offer composed of separate resources and that has a winter Capacity Supply Obligation that was adjusted as described in Section III.13.2.7.6, if the difference between the resource's winter Capacity Supply Obligation and its Winter ARA Qualified Capacity for the third annual reconfiguration auction is greater than the difference between the resource's summer Capacity Supply Obligation and Summer ARA Qualified Capacity for the third annual reconfiguration auction, then the resource's winter Capacity Supply Obligation shall be reduced such that the difference between the resource's winter Capacity Supply Obligation and its Winter ARA Qualified Capacity for the third annual reconfiguration auction equals the difference between the resource's summer Capacity Supply Obligation and Summer ARA Qualified Capacity for the third annual reconfiguration auction. For settlement purposes, any such reduction in Capacity Supply Obligation 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.13.4.2.1.2.2.3. Import Capacity Resources.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its summer Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import. For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its winter Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import.

III.13.4.2.1.2.2.4. Demand Resources.

III.13.4.2.1.2.2.4.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the lesser of: (i) its most recently-determined summer Qualified Capacity and (ii) its summer Seasonal DR Audit value in effect after the most recently completed summer season or its Demand Resource Commercial Operation Audit performed during the most recently completed summer season, whichever is more recent.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.4.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the lesser of: (i) its most recently-determined winter Qualified Capacity and (ii) its winter Seasonal DR Audit value in effect after the most recently completed winter season or its Demand Resource Commercial Operation Audit performed during the most recently completed winter season, whichever is more recent.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.3. Adjustment for Significant Decreases in Capacity.

For each month of the Capacity Commitment Period associated with the third annual reconfiguration auction, for each resource that has achieved Commercial Operation, the ISO shall subtract the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, from the amount of capacity from the resource that is subject to a Capacity Supply Obligation for the month. For the month associated with the greatest of these 12 values, if the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity (as applicable) is below the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month by more than the lesser of 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or 40 MW, then the following provisions shall apply:

(a) The Lead Market Participant may submit a written plan to the ISO with any necessary supporting documentation describing the measures that will be taken and demonstrating that the resource will be able to provide an amount of capacity consistent with its total Capacity Supply Obligation for the Capacity Commitment Period by the start of all months in that Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If submitted, such a plan must be received by the ISO no later than 10 Business Days after the ISO has notified the Lead Market Participant of its Summer ARA Qualified Capacity and Winter ARA Qualified Capacity for the third annual reconfiguration auction.

(b) If no such plan as described in Section III.13.4.2.1.3(a) is timely submitted to the ISO, or if such a plan is timely submitted but the ISO determines that the plan does not demonstrate that the resource will be able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, then the ISO shall enter a demand bid at the Forward Capacity Auction Starting Price (or, in the case of a resource that cleared in the seventh Forward Capacity Auction, at $12.11/kW-month) on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) in the third annual reconfiguration auction in an amount equal to the greatest of the 12 monthly values determined pursuant to this Section III.13.4.2.1.3.

(c) If the ISO determines that the resource is not able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, and if the resource was part of an offer composed of separate resources when it qualified to participate in the relevant Forward Capacity Auction, then before a demand bid is entered for the resource pursuant to subsection (b) above, the resource may submit monthly Capacity Supply Obligation Bilaterals to cover the deficiency for the months of the Capacity Commitment Period in which the Capacity Supply Obligation is associated with participation in an offer composed of separate resource prior to the third annual reconfiguration auction, but in no case may such a Capacity Supply Obligation Bilateral for a month be for an amount of capacity greater than the difference between the resource's Capacity Supply Obligation for the month and the resource's lowest monthly Capacity Supply Obligation during the Capacity Commitment Period.

III.13.4.2.1.4. Amount of Capacity That May Be Submitted in a Supply Offer in a Monthly Reconfiguration Auction.

A resource that has not achieved Commercial Operation by the offer and bid deadline for a monthly reconfiguration auction may not submit a supply offer for that reconfiguration auction, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a supply offer for that reconfiguration auction in an amount up to the absolute value of its Capacity Supply Obligation. The amount of capacity up to which a resource may submit a supply offer in a monthly reconfiguration auction shall be the difference (but in no case less than zero) between (i) the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity as adjusted pursuant to Section III.13.4.2, as applicable, for the auction month for the third annual reconfiguration auction for the relevant Capacity Commitment Period; and (ii) the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month. However, a resource may not submit a supply offer for a monthly reconfiguration auction if it is on an approved outage during that month.

III.13.4.2.1.5. ISO Review of Supply Offers.

Supply offers in reconfiguration auctions 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 reviews will consider the location and operating and rating limitations of resources associated with cleared supply offers to ensure reliability standards will remain satisfied if the offer is accepted. The ISO shall reject supply offers that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction. The ISO's reliability reviews will assess such offers, beginning with the marginal resource, 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. Supply offers that cannot meet the applicable reliability needs will be rejected in their entirety and the resource will not be rejected in part. Rejected resources will not be further included in clearing the reconfiguration auction and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.2.2. Demand Bids in Reconfiguration Auctions.

Submission of demand bids in reconfiguration auctions shall be governed by this Section III.13.4.2.2. All demand bids in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the amount of capacity bid in MW, and the price, in dollars per kW/month.

(a) To submit a demand bid in a reconfiguration auction, a resource must have a Capacity Supply Obligation for the Capacity Commitment Period (or portion thereof, as applicable) associated with that reconfiguration auction. Where capacity associated with a Self-Supplied FCA Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period is offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof, a resource acquiring a Capacity Supply Obligation shall not as a result become a Self-Supplied FCA Resource.

(b) Each demand bid submitted to the ISO for reconfiguration auction shall be no greater than the amount of the resource's capacity that is already obligated for the Capacity Commitment Period (or portion thereof, as applicable) as of the offer and bid deadline for the reconfiguration auction.

(c) All demand bids in reconfiguration auctions 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 reviews will consider the location and operating and rating limitations of resources associated with cleared demand bids to ensure reliability standards will remain satisfied if the committed capacity is withdrawn. The ISO shall reject demand bids that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction, provided that for annual reconfiguration auctions associated with a Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall not reject a demand bid solely on the basis that acceptance of the demand bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs). For monthly reconfiguration auctions, the ISO shall obtain and consider information from the Local Control Center regarding whether the capacity associated with demand bids that would otherwise clear from resources with a Capacity Supply Obligation is needed for local system conditions. The ISO's reliability reviews will assess such bids, beginning with the marginal resource, 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. Where the applicable reliability needs cannot be met if a Demand Bid is cleared, such Demand Bids will be rejected in their entirety and the resource will not be rejected in part. Demand Bids from rejected resources will not be further included in clearing the reconfiguration auction, and the Lead

Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.3. ISO Participation in Reconfiguration Auctions.

The ISO shall not submit supply offers or demand bids in monthly reconfiguration auctions. The ISO shall submit supply offers and demand bids in annual reconfiguration auctions as appropriate to address year-to-year changes in the Installed Capacity Requirement (net of HQICCs), Local Sourcing Requirements and Maximum Capacity Limits for the associated Capacity Commitment Period, to procure capacity not purchased in the Forward Capacity Auction as a result of the "Inadequate Supply" rule for Forward Capacity Auctions conducted prior to June 2015, to procure any shortfall in capacity resulting from a resource's achieving Commercial Operation at a level less than that resource's Capacity Supply Obligation or other significant decreases in capacity, and to address any changes in external interface limits, as follows:

(a) For each Capacity Commitment Period that begins on or before June 1, 2017, the ISO shall submit supply offers and demand bids in annual reconfiguration auctions as appropriate to ensure that the applicable Installed Capacity Requirement (net of HQICCs), Local Sourcing Requirements, Maximum Capacity Limits, and external interface limits are respected. Where less capacity than needed is obligated, the ISO shall submit demand bids as appropriate to procure the additional needed capacity in each subsequent annual reconfiguration auction until the need is met. Where more capacity than needed is obligated, the ISO may in its discretion submit supply offers in subsequent annual reconfiguration auctions to release the excess capacity, but in any case the ISO shall be required to submit supply offers as appropriate in the third annual reconfiguration auction for a Capacity Commitment Period to release the excess capacity.

(b) For each Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall submit demand bids for the amount of additional capacity needed to meet the Local Sourcing Requirements and shall submit supply offers in the third annual reconfiguration auction for a Capacity Commitment Period to release capacity exceeding the Maximum Capacity Limits or external interface limits.

(c) No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall provide notice regarding whether the ISO will be submitting supply offers or demand bids in that auction.

(d) Any demand bid submitted by the ISO in an annual reconfiguration auction shall be at the Forward Capacity Auction Starting Price, except for any demand bids submitted by the ISO in annual reconfiguration auctions associated with the seventh Capacity Commitment Period, which shall be at $12.11/kW-month.

(e) Any supply offer submitted by the ISO in an annual reconfiguration auction shall be in the form of a supply curve having the following characteristics:

(i) at prices equal to or greater than 0.75 times the Capacity Clearing Price, as adjusted pursuant to Section III.13.2.7.3(b), from the Forward Capacity Auction for the Capacity Commitment Period covered by the annual reconfiguration auction, the ISO shall offer the full amount of the surplus;

(ii) at prices between 0.75 times such Capacity Clearing Price and 0.25 times such Capacity Clearing Price, the amount of the surplus offered by the ISO shall decrease linearly (for example, at 0.5 times such Capacity Clearing Price, the ISO shall offer half of the amount of the surplus); and

(iii) At prices equal to or below 0.25 times such Capacity Clearing Price, the ISO shall offer no capacity.

(f) For purposes of this Section III.13.4.3, the Forward Capacity Auction Starting Price shall be the Forward Capacity Auction Starting Price associated with the Forward Capacity Auction for the same Capacity Commitment Period addressed by the reconfiguration auction, as determined pursuant to Section III.13.2.4.

(g) Supply offers and demand bids submitted by the ISO in annual reconfiguration auctions are not subject to the requirements and limitations described in Section III.13.4.2.

(h) Supply offers and demand bids submitted by the ISO in annual reconfiguration auctions are not associated with a resource.

III.13.4.4. Clearing Offers and Bids in Reconfiguration Auctions.

All supply offers and demand bids may be cleared in whole or in part in all reconfiguration auctions. If after clearing, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.4.5. Annual Reconfiguration Auctions.

Except as provided below, after the Forward Capacity Auction for a Capacity Commitment Period, and before the start of that Capacity Commitment Period, the ISO shall conduct three annual reconfiguration auctions for capacity commitments covering the whole of that Capacity Commitment Period. For each annual reconfiguration auction, the capacity demand curves, New England Control Area and Capacity Zone capacity requirements and external interface limits, as updated pursuant to Section III.12, shall be modeled in the auction consistent with the Forward Capacity Auction for the associated Capacity Commitment Period. For purposes of the annual reconfiguration auctions, the Forward Capacity Auction Starting Price used to define the System-Wide Capacity Demand Curve shall be the Forward Capacity Auction Starting Price associated with the Forward Capacity Auction for the same Capacity Commitment Period addressed by the reconfiguration auction.

III.13.4.5.1. Timing of Annual Reconfiguration Auctions.

Except for the first five Capacity Commitment Periods, the first annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of June that is approximately 24 months before the start of the Capacity Commitment Period. The second annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of August that is approximately 10 months before the start of the Capacity Commitment Period. The third annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of March that is approximately 3 months before the start of the Capacity Commitment Period. There shall be no first annual reconfiguration auction for the first five Capacity Commitment Periods. The table below illustrates the annual reconfiguration auction timing provisions stated above, providing the schedule of annual reconfiguration auctions for the first eight Capacity Commitment Periods.

First Annual Reconfiguration Auction	Second Annual Reconfiguration	Third Annual Reconfiguration	Capacity Commitment Period Begins
N/A	May 2009	March 2010	June 1, 2010
N/A	May 2010	March 2011	June 1, 2011
N/A	May 2011	March 2012	June 1, 2012
N/A	May 2012	March 2013	June 1, 2013
N/A	August 2013	March 2014	June 1, 2014
June 2013	August 2014	March 2015	June 1, 2015
June 2014	August 2015	March 2016	June 1, 2016
June 2015	August 2016	March 2017	June 1, 2017

III.13.4.5.2. Acceleration of Annual Reconfiguration Auction.

If the difference between the forecasted Installed Capacity Requirement (net of HQICCs) for a Capacity Commitment Period and the amount of capacity obligated for that Capacity Commitment Period is sufficiently large, then the ISO may, upon reasonable notice to Market Participants, conduct an annual reconfiguration auction as much as six months earlier than its normally-scheduled time.

III.13.4.6. [Reserved.]

III.13.4.7. Monthly Reconfiguration Auctions.

Prior to each month in the Capacity Commitment Period, the ISO shall conduct a monthly reconfiguration auction for whole-month capacity commitments during that month. For each monthly reconfiguration auction, the Local Sourcing Requirement and Maximum Capacity Limit applicable for each Capacity Zone and external interface limits, as updated pursuant to Section III.12, shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in monthly reconfiguration auctions.

III.13.4.8. Adjustment to Capacity Supply Obligations.

For each supply offer that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be increased by the amount of capacity that clears. For each demand bid that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be decreased by the amount of capacity that clears.

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 or reduced by the resource's capacity obligation in an adjacent Control Area assigned to an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented).

(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 or reduced by the resource's capacity obligation in an adjacent Control Area assigned to an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented, when a Market Participant notifies the ISO, in accordance with the ISO's annual maintenance scheduling process, that an asset associated with the External Resource is on an outage that was approved in the resource's native Control Area. 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 provisions of this Section III.13.7.1.2 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

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). 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.13.7.1.2.A. Import Capacity on External Interfaces with Enhanced Scheduling.

The following available MW determination applies to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1. The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as designed 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.A.1). The available MW in each hour that contains any portion of a Shortage Event shall be determined as follows:

(a) If the native Control Area delivers the total requested MW of Import Capacity Resources, or more than the total requested MW, then the available MW of a resource within that Control Area will be its Capacity Supply Obligation in the interval when the ISO requested delivery.

(b) If the native Control Area delivers less than the total requested MW of Import Capacity Resources, then the available MW of a resource within that Control Area in the interval when the ISO requested delivery and that contains any portion of a Shortage Event shall be established as follows:

(i) The quantity available is zero if the resource is offline in the native Control Area for the interval when the ISO requested delivery;

(ii) The quantity available is the maximum output available from the resource, as reflected in the resource's offer data, adjusted for any non-New England capacity obligation to which the resource is subject if the resource is online in the native Control Area for the interval when the ISO requested delivery.

(c) If the ISO does not request MW of Import Capacity Resources, then the available MW of a resource within that Control Area will be its Capacity Supply Obligation.

III.13.7.1.2.A.1. Availability Adjustments.

When the available MW of an Import Capacity Resource is calculated under Section III.13.7.1.2.A(b), the hourly availability score of any such Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource has complied with the provisions in Section III.13.7.1.1.4(b) for outage scheduling.

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 Resouce 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 Resouce 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, if applicable, the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015) 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 six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

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 $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-List Bid]
>
> Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.3.1.

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, 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:

Hourly PER($/kW) = [(LMP - Strike Price) * [Scaling Factor] * [Availability Factor]
Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand 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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015) 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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to “Inadequate Supply” or “Insufficient Competition”) that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015 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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to “Inadequate Supply” or “Insufficient Competition”) that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015, 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 provisions in (a) and (b) below. In addition, all Import Capacity Resources will be subject to the provisions in (c) below.

(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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015, 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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015, 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).

(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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015, divided by the number of hours in the month.

Any External Transaction submitted under Section III.1.10.7 and 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.

For Import Capacity Resources with a Capacity Obligation at an external interface for which the enhanced scheduled procedures in Section III.1.10.7.A are implemented (unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.), the requested and delivered MW are determined as follows:

(i) If the native Control Area delivers the total requested MW of Import Capacity Resources, or more than the total requested MW, then the resources within that Control Area will not be evaluated for penalties.

(ii) If the native Control Area delivers less than the total requested MW of Import Capacity Resources, then the resources will be evaluated using the following requested and delivered MW values:

1. The quantity requested is the resource's Capacity Supply Obligation; and
2. The quantity delivered for a resource is determined as follows:

a. The quantity delivered is zero if the resource is offline in the native Control Area for the interval when the ISO requested delivery;

b. The quantity delivered is the maximum output available from the resource, as reflected in the resource's offer data, adjusted for any non-New England capacity obligation to which the resource is subject if the resource is online in the native Control Area for the interval when the ISO requested deliver;

c. For purposes of this determination, the total energy delivered will be adjusted in accordance with Section III.13.7.1.1.4(b).

(iii) If the ISO does not request MW of Import Capacity Resources, then the resources within that Control Area will not be evaluated for delivery penalties.

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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015, 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.

The exceptions in Sections III.13.7.2.7.2.2.b, c and d do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduled procedures in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

a) No penalty will be assessed if the applicable external interface is fully loaded in the import direction. 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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015, 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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015 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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015, 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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015, 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, if applicable, the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015 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, if applicable, minus the lower of (1) the Capacity Clearing Price and (2) the administratively-determined payment rate (due to "Inadequate Supply" or "Insufficient Competition") that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015 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.

III.13.8. Reporting and Price Finality

III.13.8.1. Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto.

(a) For each Forward Capacity Auction, no later than 20 Business Days after the issuance of retirement determination notifications described in Section III.13.1.2.4(a), the ISO shall make a filing with the Commission pursuant to Section 205 of the Federal Power Act describing the Permanent De-List Bids and Retirement De-List Bids. The ISO will file the following information confidentially: the determinations made by the Internal Market Monitor with respect to each Permanent De-List Bid and Retirement De-List Bid, and supporting documentation for each such determination. The confidential filing shall indicate those resources that will permanently de-list or retire prior to the Forward Capacity Auction and those Permanent De-List Bids and Retirement De-List Bids for which a Lead Market Participant has made an election pursuant to Section III.13.1.2.4.1.

(b) The Forward Capacity Auction shall be conducted using the determinations as approved by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

(c) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), and (viii) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), and (viii) shall be published by the ISO no later than 15 days after the Forward Capacity Auction) , with the exception of de-list bid price information, which shall remain confidential):

(i) which Capacity Zones shall be modeled in the Forward Capacity Auction;

(ii) the transmission interface limits as determined pursuant to Section III.12.5;

(iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

(iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;

(v) the multipliers applied in determining the Capacity Value of a Demand Resource, as described in Section III.13.7.1.5.1;

(vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;

(vii) the Internal Market Monitor's determinations regarding each requested offer price from a new resource submitted pursuant to Section III.13.1.1.2.2.3 or Section III.13.1.4.2, including information regarding each of the elements considered in the Internal Market Monitor's determination of expected net revenues (other than revenues from ISO-administered markets) and whether that element was included or excluded in the determination of whether the offer is consistent with the resource's long run average costs net of expected net revenues other than capacity revenues;

(viii) the Internal Market Monitor's determinations regarding offers or Static De-List Bids, Export Bids, and Administrative De-List Bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the Internal Market Monitor-determined prices established for any Static De-List Bids, Export Bids, and Administrative De-List Bids as described in Section III.13.1.2.3.2 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. The filing shall identify to the extent possible the components of the bid which were accepted as justified, and shall also identify to the extent possible the components of the bid which were not justified and which resulted in the Internal Market Monitor establishing an Internal Market Monitor-determined price for the bid;

(ix) which existing resources are qualified to participate in the Forward Capacity Auction (this information will include resource type, capacity zone, and qualified MW); and

(x) aggregate MW from new resources qualified to participate in the Forward Capacity Auction and aggregate de-list bid amounts.

(d) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(c) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4(b) and III.13.1.3.5.7 must be filed with the Commission no later than 15 days after the ISO's submission of the informational filing. If the Commission does not issue an order within 75 days after the ISO's submission of the informational filing that directs otherwise, the determinations contained in the informational filing shall be used in conducting the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within 75 days after the ISO's submission of the informational filing, the Commission does issue an order modifying one or more of the ISO's determinations, then the Forward Capacity Auction shall be conducted no earlier than 15 days following that order using the determinations as modified by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Facility, as defined in Schedule 22 or Schedule 25 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity

Auction subject to a Long Lead Time Facility with the higher queue priority. The filing shall also enumerate bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.

(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO's filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.

(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this ***Appendix A.***

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this ***Appendix A*** shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this ***Appendix A***. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III.A.17.3 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this ***Appendix A*** are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this ***Appendix A***). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

(b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.

(c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the External Market Monitor shall perform the following functions:

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(c) Conduct evaluations and prepare reports on its own initiative or at the request of others.

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this ***Appendix A***.

(f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.

(g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this ***Appendix A***, as appropriate.

(h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the Internal Market Monitor shall perform the following functions:

(a) Maintain ***Appendix A*** and consider whether ***Appendix A*** requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.

(b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this ***Appendix A***.

(c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this ***Appendix A.***

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

(i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this ***Appendix A***.

(j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this ***Appendix A*** are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

(i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.

(ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this ***Appendix A.***

(v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend ***Appendix A*** as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

(i) Anti-competitive gaming of Resources;

(ii) Conduct and market outcomes that are inconsistent with competitive markets;

(iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;

(iv) Actions in one market that affect price in another market;

(v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this ***Appendix A***, interfere with efficient market operation, both short-run and long-run; and

(vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this ***Appendix A***. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

(m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with ***Appendix B*** of this Market Rule l.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this ***Appendix A*** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule l (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this ***Appendix A***. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this ***Appendix A***, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under ***Appendix B*** of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

(a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:

(b) Notwithstanding the foregoing or any other provision of this ***Appendix A***, and as more fully described in Section III.B.3.2.6 of ***Appendix B*** to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this ***Appendix A***, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this ***Appendix A*** or in ***Appendix B*** to this Market Rule 1.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant. In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(c) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this ***Appendix A*** for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource’s Supply Offer plus $2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm’s length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2

2 or more	6

III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
(b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,
(c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
(d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

(a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
(b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding;

(b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;

(c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.5 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

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III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

(a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;

(b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than $25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

(a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;

(b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or $100/MWh, whichever is lower. Offer block prices below $25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or $100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or $25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or $25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

i. local first contingency;
ii. local second contingency;
iii. VAR or voltage;
iv. distribution (Special Constraint Resource Service);
v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

(a) If the Resource is starting from an offline state, the Start-Up Fee;
(b) The sum of the No Load Fees for the Commitment Period; and
(c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 “General Threshold Energy Mitigation” or III.A.5.5.2 “Constrained Area Energy Mitigation” is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

   i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,

   ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 “Constrained Area Energy Mitigation”), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 “Manual Dispatch Energy Mitigation” is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource’s Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 “General Threshold Commitment Mitigation”, III.A.5.5.5 “Constrained Area Commitment Mitigation”, or III.A.5.5.6 “Reliability Commitment Mitigation” is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 “Start-Up Fee and No-Load Fee Mitigation” is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

(a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.

(b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.

(c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Supply Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of a Supply Offer according to the following hierarchy, under which the first method that can be calculated is used:

(a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;

(b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,

(c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

(a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.

(b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.

(c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.

(d) For any Operating Day for which, during the previous 90 days:

(i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;

(ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.

(iii) The Market Participant submits a fuel price pursuant to Section III.A.3.4.

For the purposes of this subsection:

i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.

ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.

iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

(e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.

(f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:

(i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,

(ii) No-Load Fee or its corresponding fuel blends,

(iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,

(iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and

(v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

(a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".

(b) Costs must be documented.

(c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible.

(d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.

(e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

    i. Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and

ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy:

(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

(a) emissions limits;

(b) water storage limits; and,

(c) other operating permits that limit production of energy.

No-Load:

(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up:

(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. Determination of Offer Competitiveness During Shortage Event.

The Internal Market Monitor shall evaluate the competitiveness of the Supply Offer of each Resource with a Capacity Supply Obligation that is off-line during a Shortage Event, as described below. The evaluation for competitiveness shall be performed on Supply Offers in the Day-Ahead Energy Market and on Supply Offers in the Real-Time Energy Market. For purposes of these evaluations, Reference Levels are calculated using the cost-based method specified in Section III.A.7.5. The Real-Time Energy Market evaluation uses the final Supply Offer in place for the hour.

(a) Hours Evaluated. For Supply Offers in the Day-Ahead Energy Market, competitiveness is evaluated for all hours of the Operating Day during which a Shortage Event occurs. For Supply Offers in the Real-Time Energy Market competitiveness is evaluated for the last hour that the Resource could have been committed to be online at its Economic Minimum Limit at the start of the Shortage Event, taking into account the Resource's Start-Up Time and Notification Time.

(b) Competitiveness Evaluation of Energy Offer At Low Load.

  (i) If the Resource is not in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

  (ii) If the Resource is in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

(c) Competitiveness Evaluation of Energy Offer Above Low Load. If a Supply Offer evaluated for competitiveness pursuant to Section III.A.8 (b) above is competitive for an hour, then the energy price parameter for each incremental Supply Offer block above the Resource's Economic Minimum Limit shall be evaluated for competitiveness using the thresholds identified in Section III.A.5.5.1.2, for Resources not in a constrained area, and the thresholds identified in Section III.A.5.5.2.2, for Resources in a constrained area, in order of lowest energy price to highest energy price. If any Supply Offer block is non-competitive, then that block and all blocks above it shall be non-competitive, and all blocks below it shall be competitive.

(d) Low Load Cost test. Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit for its Minimum Run Time, is calculated as the sum of:

  i. The Start-Up Fee (cold start);
  ii. The sum of the No Load Fees for the Resource's Minimum Run Time; and
  iii. The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Resource's Minimum Run Time.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer Block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer Block.

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor Demand Resources as outlined below:

(a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.

(b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$.

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

(i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.

(ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.

(iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England

Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor’s review and the consequences that will result from the Internal Market Monitor’s determination following such review.

(a) [Reserved].

(b) Section III.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.

(c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

(d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.

(e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.

(f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this ***Appendix A***. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer ***Appendix B*** in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.
Article 5 of the form of Cost-of-Service Agreement in ***Appendix I*** to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Filing Right.
If either

(a) as a result of mitigation applied to a Resource under this ***Appendix A*** for all or part of one or more Operating Days, or

(b) in the absence of mitigation, despite having submitted a Supply Offer at the Energy Offer Cap,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for the hours of the Operating Day during which the Supply Offer was mitigated or during which the Resource was operated at the Energy Offer Cap, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having submitted a Supply Offer at the Energy Offer Cap, costs incurred for the duration of the period of time for which the Resource was operated at the Energy Offer Cap.

III.A.15.2. Contents of Filing.
Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating

the Resource exceeded the costs as reflected in the Supply Offer at the Energy Offer Cap; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.

III.A.15.4. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in ***Appendix D*** to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.
- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully

challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this ***Appendix A***, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

(a) the opportunity costs associated with Demand Reduction Offers;

(b) the accuracy of Demand Response Baselines;

(c) the method used to achieve a demand reduction, and;

(d) the accuracy of reported demand levels.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A.***

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this ***Appendix A***.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of ***Appendix A***. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

(i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.

(ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.

(iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.

(iv) Review and assessment of the effectiveness of ***Appendix A*** and the administration of ***Appendix A*** by the Internal Market Monitor for consistency and compliance with the terms of ***Appendix A.***

(v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;

(b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;

(c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). With respect to state regulatory bodies and state attorneys general ("authorized state agencies"), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as ***Exhibit 5***.

III.A.18.2. Additional Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of ***Appendix A***, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the

Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information

- (1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);
- (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
- (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
- (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
- (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;
- (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
- (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) A detailed narrative describing the perceived market design flaw(s);

(2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;

(3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;

(4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.2.4 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Ninth Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018) shall be as follows:

Generation Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
combustion turbine	$13.424
combined cycle gas turbine	$8.866
on-shore wind	$10.320

Demand Resources - Commercial and Industrial	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management and/or previously installed Distributed Generation	$1.145
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Demand Resources – Residential	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management	$7.094

previously installed Distributed Generation	$1.145
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Other Resources

All other technology types	Forward Capacity Auction Starting Price

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

For purposes of determining the Offer Review Trigger Price of a Demand Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the new Demand Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

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

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

(c) For new Demand Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for new generation resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For new Demand Resources other than Demand Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for new generation resources, except that the model discounts cash flows over the contract life. For Demand Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Resources (other than Demand Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"
steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS “Quarterly Census of Employment and Wages” 2371 Utility System Construction Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
other labor	BLS “Quarterly Census of Employment and Wages” 2211 Power Generation and Supply Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)”
fuel inventories	Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
labor, administrative and general	BLS “Quarterly Census of Employment and Wages” 2211 Power Generation and Supply Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit

	Price Deflator (GDPDEF)”

(3) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the ninth FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the ninth FCA will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices from the time of the update through the end of the Capacity Commitment Period associated with the relevant FCA, and the Massachusetts Hub On-Peak electricity prices and the Algonquin City Gates natural gas prices for the 12 months following the time of the update, as published by the CME Group.

(5) Renewable energy credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO’s web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.2.4, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.2.4, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a new Demand Resource, the resource's costs shall
include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred by the Demand Response provider and end-use customers to acquire the Demand Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the Demand Resource, and expected costs avoided by the end-use customer as a direct result of the installation or implementation of the Demand Resource.

(iii) For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in

Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

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

III.A.21.3. Special Treatment of Certain Out-of-Market Capacity Resources in the Eighth Forward Capacity Auction.

For the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017), the provisions of Sections III.A.21.1 and III.A.21.2 shall also apply to certain resources that cleared in the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2015) and/or the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2016), as follows:

(a) This Section III.A.21.3 shall apply to: (i) any capacity clearing in the sixth or seventh Forward Capacity Auction as a New Generating Capacity Resource or New Import Capacity Resource designated as a Self-Supplied FCA Resource; and (ii) any capacity clearing in the sixth or seventh Forward Capacity Auction from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at prices found by the Internal Market Monitor to be not consistent with either: (a) the resource's long run average costs net of expected net revenues other than capacity revenues for a New Generating Capacity Resource and a New Demand Resource or (b) opportunity costs for a New Import Capacity Resource.

(b) For the eighth Forward Capacity Auction, the capacity described in subsection (a) above shall receive Offer Review Trigger Prices as described in Section III.A.21.1 and New Resource Offer Floor Prices as described in Section III.A.21.2. These values will apply to such capacity in the conduct of the eighth Forward Capacity Auction as described in Section III.13.2.3.2.

(c) For the eighth Forward Capacity Auction, the Project Sponsor or Lead Market Participant for such capacity may be required to comply with some or all of the qualification provisions applicable to new resources described in Section III.13.1. These requirements will be determined by the ISO on a case-by-case basis in consultation with the Project Sponsor or Lead Market Participant.

(d) For any capacity described in subsection (a) above that does not clear in the eighth Forward Capacity Auction:

> (i) any prior election to have a Capacity Clearing Price and Capacity Supply Obligation continue to apply for more than one Capacity Commitment Period made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 shall be terminated as of the beginning of the Capacity Commitment Period associated with the eighth FCA (beginning June 1, 2017); and
>
> (ii) after the eighth Forward Capacity Auction, such capacity will be deemed to have never been previously counted as capacity, such that it meets the definition, and must meet the requirements, of a new capacity resource for the subsequent Forward Capacity Auction in which it seeks to participate.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources in the Rest-of-Pool Capacity Zone;
(b) For each modeled import-constrained Capacity Zone, the greater of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
(c) For each modeled export-constrained Capacity Zone, the lesser of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the export-constrained Capacity Zone plus, for each external interface connected to the export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Maximum Capacity Limit of the export-constrained Capacity Zone, and;
(d) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(e) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources located within the import-constrained Capacity Zone; and

(f) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.

(b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import

Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than

ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
ISO New England Inc. and	)	**Docket No. ER16-____-000**
New England Power Pool	)	
Participants Committee	)	
	)	

PREPARED TESTIMONY OF
CHRISTOPHER GEISSLER AND MATTHEW WHITE
ON BEHALF OF
ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

Q: Please state your name, position and business address.

A: *Dr. Geissler*: My name is Christopher Geissler. I am an Economist for ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Dr. White: My name is Matthew White. I am the Chief Economist for the ISO. My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: Dr. Geissler, please describe your responsibilities, work experience and educational background.

A: My primary responsibilities include wholesale electricity market design and development, with an emphasis on the ISO's Forward Capacity Market.[1] Among other projects, I helped to develop the ISO's pioneering two-settlement capacity market design (also known as the "Pay for Performance" capacity market design) that was accepted by the Commission in 2014 in Docket No. ER14-2419. I am an instructor for the energy market sections of the ISO's Wholesale Energy Markets course for ISO staff and Market Participants. Prior to joining the ISO in 2013, I received an M.A. and Ph.D. in Economics from Duke University where I conducted research on competition in regulated industries.

Q: Dr. White, please describe your responsibilities, work experience and educational background.

A: My primary responsibilities at the ISO include the design and development of the ISO's suite of auction-based electricity markets. Prior to joining the ISO, I held faculty appointments at the University of Pennsylvania's Wharton School of Finance and Commerce (2002-2009) and Stanford University's Graduate School of Business (1995-2001). At these institutions I conducted research on electricity demand, pricing, and market design, and taught graduate-level courses in economics and decision analysis. My public service includes appointments as a senior staff economist at the Federal Energy Regulatory Commission, Office of Energy Policy and Innovation (2009-2010) and the Federal Trade Commission, Bureau of Economics (2001-2002). My research studies have been published in

[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 (the "Tariff"), the Second Restated New England Power Pool Agreement and the Participants Agreement.

peer-reviewed economics journals, and I have served as a referee and evaluator for the National Science Foundation and over twenty-five journals spanning economics, engineering, and political science. I received a M.S. in Statistics and a Ph.D. in Economics from the University of California, Berkeley.

Q: What role did you play in the development of the ISO's demand curve design improvements addressed in this testimony?

A: *Dr. Geissler:* I served as the ISO's project lead for developing many of design elements of the demand curve improvements (referred to hereafter as the Demand Curve Design Improvements"). In addition, I explained the new design in detail to the region's stakeholders over the course of a six-month stakeholder process.

Dr. White: I supervised the overall development of the Demand Curve Design Improvements by a team of qualified professionals, employed by the ISO, consisting of engineers, economists, optimization specialists, data analysts and information technology experts. In addition, I was the principal author of the ISO's December 7, 2015 technical memorandum to the NEPOOL Markets Committee on the FCM Zonal Demand Curve Methodology (hereafter, the "Technical Memorandum"), which is incorporated by reference in this testimony and included with this filing as Attachment 2.

Q: Dr. White, were all of the materials presented in this testimony prepared under your supervision?

A: Yes.

II. PURPOSE AND ORGANIZATION OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of our testimony is to explain the Demand Curve Design Improvements, including the rationale for, and benefits of, the improvements.

Q: Please provide a high-level overview of the Demand Curve Design Improvements.

A: As the Commission is aware, the ISO and its stakeholders have been working for some time to develop a design for sloped demand curves that could be used for the constrained capacity zones in the Forward Capacity Market.[2] The ISO initially intended to have a new design in place for the Forward Capacity Auction held in February 2016 ("FCA 10"). The effort to develop a new design for FCA 10 was based on an approach that would have retained the existing system-wide demand curve design, while replacing the existing fixed zonal capacity requirements with sloping demand curves.

In early 2015, the ISO concluded that its initial zonal demand curve approach had unacceptable shortcomings. Specifically, that approach was not able to produce a

[2] *See ISO New England Inc. and New England Power Pool Participants Committee*, Docket No. ER14-1639-000, Report on Progress Toward Developing Zonal Demand Curve Improvements (October 30, 2015).

robust set of zonal demand curves; that is, a set of demand curves that would perform well under a broad range of potential future system and market conditions. Accordingly, the ISO advised the Commission in early 2015 that it was unable to implement a new zonal demand curve design for FCA 10 and that it would focus concerted effort and additional resources on developing a new capacity demand curve design that could be implemented for the Forward Capacity Auction to be held in February 2017 ("FCA 11"). In October 2015, the ISO reported to the Commission that it was engaged with stakeholders in developing a new, promising demand curve design that would use the ISO's full-scale reliability planning simulation system (known as Multi-Area Reliability Simulation, or "MARS") to develop demand curves for the Forward Capacity Market.

The ISO is pleased to report that its continued design effort has produced a demand curve design that performs well across a broad range of potential future system and market conditions, including a wide variety of potential capacity zone configurations. Furthermore, these design improvements satisfy the design criteria that the ISO and Commission have used to evaluate the performance of potential demand curve designs in the past.

As discussed in detail in this testimony, the Demand Curve Design Improvements are based on sound economic foundations and satisfy several central design principles. These principles include satisfying the reliability and resource adequacy planning standards for the power system, assuring the long-term sustainability of new entry and capacity investment, and procuring capacity cost-effectively in each capacity zone.

The Demand Curve Design Improvements achieve these principles by employing quantitative, engineering-economic analyses of the incremental reliability impact of additional capacity in each location of the New England system. Specifically, the new demand curve design specifies prices for each capacity zone that are based, in a precise way, on the Marginal Reliability Impact (or "MRI") of incremental capacity in different zones. Because the Demand Curve Design Improvements are based on sound engineering-economic foundations, they will improve the locational price signals for capacity investment in New England, procure capacity based on the actual reliability impact of additional capacity, and achieve the desired design principles (*viz.*, reliability, sustainability and cost-effectiveness) under a wide variety of potential future zonal configurations and market conditions.

Q: How is your testimony organized?

A: Following this introductory section, the testimony is organized as follows:

- Section III discusses the rationale for the Demand Curve Design Improvements, including the problems with the existing capacity market demand curves.

- Section IV explains the objectives and central design principles of the Demand Curve Design Improvements.

- Section V describes the key components of the Demand Curve Design Improvements, including Marginal Reliability Impact values and their application to derive demand curves for import-constrained zones, export-constrained zones, and the system overall. This section also explains the process for updating the demand curves' specific values for each Forward Capacity Auction.

- Section VI explains how and why the new demand curve design procures capacity cost-effectively in each capacity zone and further explains why demand curves that differ from the ISO's new design would not achieve that objective.

- Section VII explains how the Demand Curve Design Improvements enable capacity in one zone to substitute, in part, for procuring more expensive capacity in another zone during the clearing of the Forward Capacity Auction (or "FCA"). This is a key feature of the new design that improves both auction competitiveness and reliability outcomes.

- Section VIII discusses the ISO's quantitative analysis of the Demand Curve Design Improvements and demonstrates that the new design yields capacity demand curves that perform well under a range of supply conditions and zonal configurations.

- Section IX explains that the Demand Curve Design Improvements allow for the elimination of the existing administrative pricing rules that were originally adopted to protect against the potential exercise of market power due to the use of fixed zonal capacity requirements in the FCA.

- Finally, Section X outlines the transition period that uses a modified system demand curve and explains several ancillary technical aspects of the Demand Curve Design Improvements, including conforming changes to the FCA's descending clock auction closing conditions and the calculation of excess supply values at the end of each auction round.

III. RATIONALE FOR THE DEMAND CURVE DESIGN IMPROVEMENTS

Q: At a high level, what is the rationale for the Demand Curve Design Improvements?

A: There are several characteristics of the existing capacity demand curves that are contrary to sound economics and impair the Forward Capacity Market's performance. We summarize these characteristics at a high level here and address their more technical elements in later sections of this testimony.

As is widely recognized, a major deficiency of the Forward Capacity Market's current demand curve design is that it employs fixed capacity procurement requirements for constrained capacity zones. From an economic perspective, each of these fixed requirements can be viewed as a price-*insensitive*, or "vertical," demand curve for the capacity zone.[3] As the Commission observed in its December 28, 2015 order in this proceeding,[4] vertical demand curves can produce large capacity price changes in response to minute changes in capacity supply. This can create zonal price volatility that is neither necessary nor reflective of sound economic fundamentals.

As a consequence, using price-insensitive, vertical demand curves can send poor locational capacity price signals – price signals that are divorced from capacity's incremental reliability impact in each zone. Given the shifts in New England's capacity supply situation in recent years, it has become even more important to ensure that the Forward Capacity Market produces accurate price signals – a point the Commission noted expressly in the December 28 Order and its order issued on January 24, 2014.[5]

[3] Economists commonly term demand curves that are price *insensitive* as "perfectly price *inelastic*." We use the former herein for clarity.

[4] *ISO New England Inc., et al., Order Instituting Section 206 Proceeding,* 153 FERC ¶ 61,338 at P 12 (2015) (the "December 28 Order").

[5] *Id., citing New England Power Generators Association, Inc. v. ISO New England Inc., Order on Complaint,* 146 FERC ¶ 61,038 at P 26 (2014) (the "January 24 Order") .

Q: Again at a high-level, are there any deficiencies in the current System-Wide Capacity Demand Curve that are addressed by the Demand Curve Design Improvements?

A: Yes. By way of background, the New England region adopted a sloped System-Wide Capacity Demand Curve two years ago and initially implemented it in the Forward Capacity Auction conducted in February 2015 ("FCA 9"). That curve, which employs a downward-sloping, linear function (*i.e.*, a straight line) to define a demand "curve," was quickly developed by the ISO and the region's stakeholders in response to the January 24 Order. Since that time, and with the benefit of considerable new information and technical analyses that it has performed as part of the Demand Curve Design Improvements, the ISO has identified certain material deficiencies in the current, linear System-Wide Capacity Demand Curve design.

In particular, the current System-Wide Capacity Demand Curve design does not procure capacity cost-effectively. That is, under a broad range of supply conditions, it results in procuring more capacity than is necessary to meet the region's resource adequacy objectives. In addition, in many scenarios it may result in procuring too much capacity in some capacity zones (*viz.*, the Rest-of-Pool Capacity Zone) and too little capacity in others (*viz.*, constrained capacity zones), relative to the least-cost balance of capacity among these zones that yields the same overall system reliability. We explain this deficiency, and how the Demand Curve Design Improvements correct it, in detail in Sections V and VI of this testimony. Correcting this deficiency requires modifications to the current linear specification of the system demand curve and will enable the Forward Capacity Market to achieve the overall system planning reliability objective at lower expected cost.

Taken together, the overarching rationale for the Demand Curve Design Improvements is to replace vertical demand curves for constrained capacity zones with appropriately designed, downward-sloping demand curves and to make related changes to the system-wide curve that will materially improve the performance of the Forward Capacity Market.

Q: Please explain why employing vertical zonal demand curves impairs the performance of the Forward Capacity Market.

A: The crux of the problem with vertical capacity demand curves is that they are based on the assumption that there is a strict, fixed requirement for how much capacity must be located within an import-constrained capacity zone to ensure reliability (and, similarly, that there is a strict, maximum limit on how much capacity can be located within an export-constrained capacity zone that contributes to the rest of the system's reliability). While the use of a fixed capacity requirement has been a workable, simplifying assumption for purposes of administering the capacity market, from an engineering-economic standpoint it does not accurately reflect the actual reliability impact of adding (or removing) capacity above (or below) the fixed requirement. In reality, overall reliability varies in a smooth, incremental way when incremental capacity is added to any capacity zone; that is, reliability does not change abruptly when the amount of capacity varies from just below, to just above, any fixed capacity level.

As a consequence, even after the fixed capacity requirement represented by a vertical demand curve has been satisfied, the addition of incremental capacity in an import-constrained zone will continue to improve reliability (with the incremental improvement gradually diminishing as more capacity is added). The failure of a fixed capacity requirement design to accurately reflect the marginal reliability impact of capacity is the root cause why vertical zonal demand curves are a poor market design.

Q: If vertical zonal demand curves are a poor market design, what specifically are their adverse consequences?

A: The adverse consequences of vertical zonal demand curves are poor locational price signals for capacity investment, a balance of capacity among zones that is not cost effective, unnecessary price volatility, and susceptibility to market power in constrained zones. We address each of these four issues in turn.

First, vertical zonal demand curves produce poor price signals because they do not reflect the relative marginal reliability impact of procuring additional capacity in one capacity zone, instead of another zone. For example, when an import-constrained zone is slightly short of a fixed capacity requirement, a vertical demand curve may signal inappropriately high prices that over-compensate resources in that zone; conversely, when the zone is slightly long of a fixed capacity requirement, a vertical demand curve may signal inappropriately low prices that under-compensate resources. Despite the significant difference in the prices specified in these two cases, the actual incremental reliability benefit of adding a little more capacity is nearly the same in each. Consequently, vertical zonal demand curves send poor locational price signals that tend to over-compensate resources (relative to their incremental reliability benefit) when their zone's capacity is below a fixed capacity requirement, and tend to under-compensate resources (relative to their incremental reliability benefit) when their zone's capacity is above the fixed capacity requirement.

Second, vertical zonal demand curves fail to procure capacity cost-effectively because they do not recognize that, from a reliability perspective, capacity is "partially substitutable" between the Rest-of-Pool Capacity Zone and constrained capacity zones at the margin. That is, in any Forward Capacity Auction, it may be possible to meet system's overall reliability planning objective by purchasing more capacity in a lower-price, unconstrained area of the system, and purchasing less than the fixed capacity requirement in a higher-price, import-constrained zone. Procuring capacity in this manner can provide equivalent system reliability at lower cost – thereby improving the cost-effectiveness of the Forward Capacity Market. We explain this, with examples, in detail in Sections VI and VII of this testimony. Unfortunately, vertical zonal demand curves completely ignore the partial substitutability of capacity between zones and therefore do not permit these cost-effective trade-offs to occur at all.

Third, vertical zonal demand curves result in unnecessary capacity price volatility in capacity zones. This is a consequence of the same problem noted previously, and discussed in the December 28 Order: incremental changes in capacity supply (*i.e.*, from just below to just above the fixed requirement) can yield large capacity price swings. This is unnecessary inasmuch as it does not reflect sound economic fundamentals – in this case, incremental capacity's marginal reliability impact. Price volatility that does not reflect sound economic fundamentals can have adverse consequences because it can be expected to increase financial risk for capacity investors, which may inefficiently and unnecessarily raise the cost of capacity in the Forward Capacity Market.

Finally, for the same reason that vertical zonal demand curves result in unnecessary price volatility (*i.e.*, the potential for small changes in quantity to result in large price swings), they also make import-constrained zones more susceptible to the exercise of market power. By their nature, vertical demand curves can provide strong financial incentives for a large supplier to withhold a portion of its potential supply in order to profit from dramatically increased prices. Sloped demand curves, along with capacity substitutability among capacity zones, can significantly attenuate this market power concern. The susceptibility of import-constrained capacity zones with vertical demand curves to market power was one of the concerns specifically identified in the December 28 Order.

Q: What are the problems associated with the existing System-Wide Capacity Demand Curve and its interaction with zonal demand curves?

A: Many of the concerns associated with zonal demand curves are also applicable to the current system-wide demand curve. The system-wide demand curve has a sloped, linear design that implicitly acknowledges, in a qualitative way, that there is a gradually diminishing reliability impact of adding more capacity at the system level. However, the current linear system-wide demand curve was not based on any engineering-economic analyses of the actual marginal reliability impact of adding capacity, and as discussed in detail in Section V, the current system demand curve does not accurately reflect these engineering-economic fundamentals. Accordingly, like the existing vertical zonal demand curves, modifications to the existing system-wide demand curve that better align its design to these engineering-economic fundamentals can be expected to yield equivalent or superior reliability outcomes at lower cost.

The ISO's analysis also indicates that it is difficult (and perhaps impossible) to achieve an overall capacity market design that is robust to potential future market conditions and zonal configurations unless the system-wide and zonal demand curves are designed using the same methodology and properly account for the partial substitutability of capacity between zones. A robust design will perform well across a range of potential zonal configurations from a reliability perspective. It will also produce sound locational price signals for investment – meaning, specifically, prices reflect the relative marginal reliability impact of capacity in each zone. The ISO's initial effort to develop zonal demand curves (for FCA 10) proved unsuccessful because the inherent incompatibilities between system-wide and zonal demand curves that are not based on a coordinated, engineering-economic marginal reliability impact analysis cannot produce a design that works under a wide variety of zonal configurations and market conditions.

Q: Please summarize how the Demand Curve Design Improvements address both the problems associated with the vertical zonal demand curves and the deficiencies in the existing system-wide demand curve to improve the capacity market's performance.

A: The fundamental market design insight underlying the Demand Curve Design Improvements is that the system-wide and zonal demand curves are interdependent,[6] and must be designed in conjunction with one another in order to achieve the region's reliability planning objectives while procuring capacity cost-effectively. In addition, it is clear that a set of demand curves that achieves these goals and is robust to potential changes in zonal configurations cannot be static. Instead, it must be based on a sound engineering-economic methodology that makes it simple and straightforward to produce updated demand curves when there are changes in market conditions (such as future load forecasts) or to the

[6] *See also* Potomac Economics (External Market Monitor), 2014 Assessment of the ISO New England Electricity Markets (June 2015), Section V.B.2, p. 97.

market's zonal configuration. In this way, the Demand Curve Design Improvements will ensure that all of the demand curves used in the Forward Capacity Market work well together even though the New England power system may evolve significantly over time.

The key to achieving this outcome is in the re-design of both the system-wide and zonal demand curves so that each will specify prices that more accurately reflect the locational marginal reliability impact of capacity than the current demand curves. Using marginal reliability impact-based curves produces better locational price signals at both the system and zonal levels, and enables the Forward Capacity Auction to clear the capacity market in a way that accounts for the partial substitutability of capacity between constrained capacity zones and the Rest-of-Pool Capacity Zone. Finally, the sloped zonal demand curves reduce the price volatility and market power concerns associated with the existing vertical demand curves, and enable the removal of certain administrative pricing provisions adopted to address market power issues present with vertical capacity demand curves.

IV. THE DEMAND CURVE DESIGN IMPROVEMENTS ARE BASED ON SOUND PRINCIPLES AND OBJECTIVES

Q: Are the Demand Curve Design Improvements based on any specific design principles?

A: Yes. The ISO employed a principles-based approach to develop the Demand Curve Design Improvements. Specifically, we began the design process with three central market design principles that are consistent with the capacity market's objectives. We then developed the Demand Curve Design Improvements to satisfy these three central design principles.

Q: What are the three central design principles that the Demand Curve Design Improvements aim to satisfy?

A: The Demand Curve Design Improvements satisfy three principles broadly applicable to sound capacity market design. The first principle is *reliability:* The demand curve design should procure sufficient capacity to meet the region's reliability planning objective. (This is also called a "resource adequacy" objective). The second principle is *sustainability:* The demand curve design – and the capacity market more generally – should provide sufficient compensation to capacity suppliers to sustain adequate investment to meet the reliability objective over the long-term. The third principle is *cost-effectiveness:* The demand curve design should allocate capacity purchases among capacity zones in a way that minimizes the total bid-cost of procuring capacity overall, while satisfying the reliability and sustainability objectives.

Q: Please explain the reliability principle.

A: To comply with regional reliability standards, the ISO must plan the New England system to meet a "1-day-in-10" Loss of Load Expectation planning standard.[7] As noted, in system planning parlance, this planning standard is also known as the system's resource adequacy objective.

In a system with multiple capacity zones, this planning standard is not applied to each capacity zone in isolation. Rather, it applies to the loss of load expectation due to resource inadequacy for the system overall. Because interface transfer limits between capacity zones can limit the ability of capacity in one zone to serve load in another zone, both the total capacity in the system as well as the share of total capacity in each capacity zone will determine whether the resource adequacy objective is satisfied.

Importantly, from the standpoint of engineering-economic fundamentals, there is not a set minimum capacity level in each capacity zone to satisfy the resource adequacy objective. As noted in Section III, the ISO's prior use of a fixed capacity requirement for capacity zones has been a workable, simplifying assumption for purposes of administering the capacity market. In practice, however, there are a variety of combinations of different capacity levels among the zones that will suffice to achieve the resource adequacy objective. The new sloped demand curves are designed cognizant of these engineering-economic relationships, and are structured to procure a combination of capacity levels

[7] *See* NPCC Reliability Reference Directory # 1, Design and Operation of the Bulk Power System, 3.0 (NPCC Full Member Criteria), Resource Adequacy (R4).

among the zones that meets the system's resource adequacy objective. The exact combination will depend on the price of supply offered in each zone.

Q: Please explain the sustainability principle.

A: In order to ensure that the region can satisfy its resource adequacy objective over the long-term, the FCM must induce entry of new capacity resources periodically to replace retiring resources and to address anticipated load growth. To ensure that entry will occur in such circumstances, potential capacity suppliers must expect to recover their investment costs, including an acceptable return on capital. This investment cost, including the expected return on capital and adjusted for any net revenue from the provision of energy and ancillary services, is their net cost of new entry.

In a competitive capacity market, investors will be willing to undertake new entry and supply capacity, over the long-term, if they expect the average capacity market price to equal or exceed their net cost of new entry. For purposes of administering the Forward Capacity Market, the ISO performs studies to estimate the net cost of new entry ("Net CONE") in New England. To satisfy the market's sustainability principle, the demand curves are designed to yield an average market clearing price of at least Net CONE.

Q: How do the reliability and sustainability principles differ? Do they apply to different aspects of a capacity demand curve?

A: The reliability and the sustainability principles are closely inter-related, but they are distinct. To satisfy the reliability principle, the demand curves must be designed to procure sufficient quantities in each zone to satisfy the resource adequacy objective; to simultaneously satisfy the sustainability principle, the demand curves must also yield an average market clearing price of at least Net CONE.

In economic analysis, demand curves are often represented graphically with the demand curve's price (on a vertical axis) expressed as a function of quantity (on a horizontal axis). In simplified terms, the reliability and sustainability principles – in tandem – will preclude demand curves from being situated too far to the "left" (*i.e.*, too close to the origin). Demand curves that are too far to the "left" will procure insufficient capacity to satisfy the resource adequacy objective, when evaluated at a price of Net CONE.

Importantly, these principles do not imply that the price specified by the demand curves must pay at least Net CONE in each year's capacity auction. When the system has excess capacity – *i.e.*, more than necessary to satisfy the resource adequacy objective – then the demand curves should allow the market price of one or more capacity zones to fall *below* Net CONE, in order to deter investment in additional capacity that would not be needed. Similarly, if the system has insufficient capacity to satisfy the resource adequacy objective, then the demand curves should enable the market price to rise *above* Net CONE, in order to induce the entry of additional capacity resources.

Q: Please explain the cost-effectiveness design principle.

A: As noted previously, when there are multiple zones, it is possible to satisfy the reliability principle with a variety of combinations of different capacity levels among the zones. This feature introduces an important market design issue that is not present in unconstrained systems (that is, in systems without capacity zones). Specifically, it is possible to have a variety of combinations of different capacity levels among the zones that yield the same overall system reliability; however, since supply in each zone is commonly offered at different prices, some of these different combinations may have a higher cost than others. In simple terms, the cost-effective design principle means that in these situations, the demand curves should procure the combination with the lowest cost.

Stated more precisely, a set of demand curves satisfies the cost-effectiveness design principle if, for each possible combination of clearing prices among the zones, there is no alternate combination of capacity quantities – that is, alternate to the quantities specified by the demand curves – that would yield the same or better reliability at a lower total bid-cost. This property is consistent with sound market design as it ensures that there is no "better" alternate set of curves that could produce equal system reliability at lower total bid-cost.

Q: Conceptually, how does the cost-effectiveness principle guide the design of capacity demand curves?

A: The cost-effective design principle has a significant effect on the design of capacity demand curves. Conceptually, this principle implies that capacity demand curves should reflect capacity's incremental impact on reliability. We explain this at a conceptual level here, and then in greater detail in Section VI of this testimony.

When there are multiple capacity zones, it is important to design demand curves that appropriately balance the cost and benefit of procuring incremental capacity in each location. In this context, the benefit of procuring incremental capacity is that it reduces the system's expected loss of load. The cost of procuring incremental capacity is the price. The cost-effectiveness principle implies that in each zone, there should be the same incremental cost of capacity *relative to* its incremental reliability benefit.

This does not imply capacity should have the same price in every zone. Another increment of capacity in an import-constrained zone may have greater reliability benefit than in the Rest-of-Pool Capacity Zone, and command a commensurately higher price, for example. Rather, the cost-effectiveness principle implies that when procuring capacity, the *ratio* of incremental cost to incremental benefit should be equalized for all capacity zones. When a set of capacity demand curves achieves this outcome, it will ensure that there is no "better" set of demand curves that could produce the same or greater system reliability at a lower total bid-cost.

Q: **Could you provide a simple example? Please explain further.**

A: Yes. A simple, two-zone example will help to explain this concept and its importance for designing capacity demand curves.

Imagine there are two capacity zones: An import-constrained capacity zone (called zone A), and the Rest-of-Pool Capacity Zone (called zone B). Suppose first that at a particular combination of capacity levels in zone A and zone B, the demand curve's price in zone A is <u>twice</u> the demand curve's price in zone B. Suppose further that procuring 1 MW more capacity in either zone A or B would reduce the system's expected loss of load by the <u>same</u> amount. That is, a MW of incremental capacity in either zone would yield the same reliability improvement.

In this scenario, the capacity demand curves are *not* cost-effective. At these prices, the demand curves procure too much capacity in zone A, relative to the amount procured in zone B. The reason is simple: If we procure a little less in zone A, where it has a higher price, and commensurately more in zone B, where it has a lower price, overall reliability is the same – but the total cost would be lower. In other words, in this scenario, the quantities specified by the zonal demand curves are not cost effective.

Alternatively, let's now modify this scenario to consider demand curves that are cost-effective. Assume – as before – that the price in zone A is twice the price in zone B. Suppose now that the demand curves are modified to procure different quantities at these prices. Specifically, suppose they procure a combination of capacity levels in zone A and zone B where an additional 1 MW of capacity in zone A would improve reliability by *twice* as much as an additional 1 MW of capacity in zone B. (The demand curves that accomplish this would purchase less capacity in zone A, and more in zone B, than in the prior scenario). Although both the cost and the benefit of an additional 1 MW of capacity are now twice as large in zone B than in zone A, each zone has the same *ratio* of incremental cost to incremental benefit.

In this second scenario, there is no way to demand a little less capacity in one zone and a little more in the other that would reduce the total bid-cost of capacity while achieving the same loss of load expectation. Consequently, at these prices, the balance of capacity demanded in each zone is the most cost-effective means to achieve that level of reliability.

Q: Does this mean that if the reliability improvement of an incremental unit of capacity is (say) 125% higher in one zone than another, the price should also be 125% higher?

A: Yes, exactly. If the demand curves procure a combination of capacity levels in the zones such that the reliability improvement of incremental capacity is 125 percent higher in one zone than in another, then the price specified by the demand curves (at those capacity levels) should also be 125 percent higher in the former zone than the latter. This "proportionality property" holds generally; that is, if the incremental reliability improvement is (say) 150 percent higher in one zone than in another, the price should be 150 percent higher; if the reliability improvement is 200 percent higher, the price should be 200 percent higher; and so forth.

This proportionality property provides considerable guidance for the design of capacity demand curves, as a practical matter. In effect, it means that to be cost-effective, at each possible capacity level the demand curves should specify a zonal price that is proportional to the incremental reliability improvement (*i.e.*, the reduction in expected loss of load) from procuring 1 MW more capacity.

Q: How is this property applied to construct cost-effective demand curves?

A: From a design standpoint, applying this property entails two essential steps. The first is that it is necessary to assess, quantitatively, the incremental reliability improvement (*i.e.*, the reduction in expected loss of load) from procuring incremental capacity, for each possible capacity level in each zone. The second step is to set the prices for each demand curve proportional to this incremental reliability improvement.

In practice, the first step is an empirical exercise in engineering-economic analysis, which the ISO conducts using industry-standard reliability planning simulation models. The relationship between capacity and its incremental reliability impact on expected loss of load is known as the Marginal Reliability Impact ("MRI") of capacity. We explain how the MRI curves are calculated for each zone in detail in Section V of this testimony, below.

The second step of the process is to set the prices for each capacity demand curve proportional to the Marginal Reliability Impact of capacity. Relative to the first step, this second step is comparatively simple: it involves determining the appropriate factor of proportionality. The factor of proportionality is just a number – a conversion factor – that converts the beneficial reliability impact of capacity (in terms of expected lost load per year) into prices (in terms of dollars/kW-year). The appropriate factor of proportionality is not arbitrary, and can be determined by applying the reliability and sustainability principles discussed earlier. We explain this second step of the process in detail in Section V.B of this testimony, below.

In summary, by following this two-step process for constructing capacity demand curves, the capacity demand curves will satisfy the three central design principles of reliability, sustainability, and cost-effectiveness.

Q: Does this imply that any set of demand curves that does not apply this process will not be cost effective?

A: Yes, that is correct. When there are one or more constrained capacity zones, then a set of demand curves that do not specify zonal prices in proportion to the Marginal Reliability Impact of capacity in each zone will not be cost-effective.

This is a powerful economic insight, as it tightly circumscribes the set of capacity demand curve designs that will satisfy the three central design principles. That is, for all practical intents and purposes, following this two-step process is the *only* way to construct capacity demand curves for a multi-zone capacity market that will satisfy the three central design principles.

Q: Did you consider any other design objectives when developing these Demand Curve Design Improvements?

A: Yes. As noted in Section III of this testimony, the ISO sought to ensure that the demand curve design would perform well across a broad range of potential Capacity Zone configurations that may arise in New England over time. The demand curve inputs, including the zonal configuration, would simply need to be updated and the same two-step curve construction process applied. In other words, even if the New England system changes significantly, the updated demand curves will continue to satisfy their three central design principles.

Q: How do the Demand Curve Design Improvements ensure that the design principles are satisfied across a range of potential zonal configurations or other system changes?

A: The Demand Curve Design Improvements do not provide for a static set of demand curves. Rather, they provide a clear method to produce demand curves that are specific to the zonal configuration and associated system planning parameters for each year (in this context, associated system planning parameters include, *e.g.*, system and zonal load forecasts, transfer capabilities between capacity zones, and other system planning inputs reviewed annually by the ISO and stakeholders[8]). This method is designed to produce a unique set of capacity demand curves that satisfy the three central design principles for any set of potential capacity zones and associated system planning parameters.

Q: Do the Demand Curve Design Improvements lead to capacity demand curves that are less predictable from one year to the next than under current rules?

A: No. There are two primary reasons that the demand curves may change from year to year. With respect to each of these reasons, the predictability of the capacity demand curves under the current rules and under the Demand Curve Design Improvements are comparable.

First, the system planning parameters (for the system or for a constrained zone) may change from one year to the next. As noted in response to the preceding question, such parameters include system and zonal load forecasts, transfer capabilities between zones, and so on. As occurs with the existing linear system demand curve and the vertical zonal demand curves, changes to these parameters

[8] These inputs are summarized in ISO's annual *ICR Related Values Report*, available at http://www.iso-ne.com/system-planning/resource-planning/installed-capacity-requirements.

will alter the amount of capacity demanded, generally shifting the demand curves left or right in a reasonably predictable manner. (References to "left" or "right" refer to graphical depictions of demand curves where, as is customary in economics, price is represented on a vertical axis and quantity on a horizontal axis. A shift "left" moves the demand curve closer to the origin, procuring less capacity at every price; a shift "right" does the opposite). As a common example, if there is an increase in the system load forecast from one year to the next that increases the Installed Capacity Requirement by (say) 100 MW under the existing rules, then under the Demand Curve Design Improvements the MRI-based system demand curve will similarly increase (*i.e.*, it will shift "right") by approximately 100 MW.

The second primary reason a demand curve may change from year to year is if a new capacity zone is to be modeled in the Forward Capacity Auction (or a prior zone is no longer to be modeled). Under both the existing rules and the Demand Curve Design Improvements, the introduction of a new capacity zone would require the development of a corresponding new zonal demand curve. While the exact shape of the curve for a new capacity zone may not be known precisely before the zone is fully studied, zonal demand curves based on the Marginal Reliability Impact of capacity have a characteristic general shape. Thus, when a new zone is under initial study, we expect that the level of predictability about the new zone's demand curve would tend to be comparable under the existing rules and the new design.

Q: Broadly, what are the benefits of using a set of capacity demand curves that satisfy the three central design principles?

A: The benefits are numerous. The Demand Curve Design Improvements meet the resource adequacy objective while improving locational price signals for investment, decreasing the expected total cost of capacity, reducing zonal price volatility, and attenuating market power concerns.

Q: How do the Demand Curve Design Improvements improve locational price signals for investment?

A: Project developers make investment decisions based on capacity prices and project costs; they are not expected to evaluate their project's impact on system reliability *per se*. The cost-effectiveness principle ensures that the capacity price is proportional to its reliability impact for all capacity quantities and zones. As a result, when a capacity investment decision is based on the capacity price and the project's costs, it is implicitly reflecting both the incremental reliability benefit and incremental cost of adding capacity to that zone. Consequently, prices based on the incremental reliability benefit of additional capacity can provide better locational investment signals that guide investment more efficiently than today – toward the capacity zone(s) for which the reliability benefit, relative to the project's cost, is greatest.

Q: How does the design decrease the expected cost of capacity?

A: The cost-effectiveness principle ensures that there are no alternative "better" demand curves that can achieve the same overall reliability at a lower total bid-cost. That is, the capacity demand curves based on these Demand Curve Design Improvements are the least-cost means to meet the system's overall resource adequacy objective. In contrast, any alternative set of curves would incur higher expected cost to meet the same resource adequacy objective. These higher-cost alternatives include the current linear system demand curve and vertical zonal demand curves, which were not developed based on the Marginal Reliability Impact of capacity – and therefore do not satisfy the cost-effectiveness principle.

We provide an assessment of the change in expected total capacity payments, under a variety of capacity supply scenarios, at the end of Section VIII of this testimony.

Q: How do the Demand Curve Design Improvements reduce zonal price volatility?

A: The current design uses fixed requirements for constrained capacity zones. As the Commission notes in its December 28 Order, "when vertical demand curves are used, even small increases or decreases in supply can result in large changes in price, because a fixed amount of capacity must be procured." (P 12). As shown in detail in Section V of this testimony, sloped zonal demand curves address this problem by allowing prices to adjust more gradually with changes in supply. This new design will therefore reduce price volatility in constrained zones.

Q: How do the Demand Curve Design Improvements attenuate market power concerns?

A: The introduction of sloped demand curves for constrained capacity zones reduces the potential price impact associated with withholding capacity supply. This reduces the financial incentive for a large capacity supplier to exercise market power in a constrained capacity zone. Furthermore, the Demand Curve Design Improvements also affect how capacity awards are determined in the conduct of the Forward Capacity Auction, so that clearing prices and quantities are interdependent across capacity zones. This interdependence is a feature of the "partial substitutability" property of capacity discussed previously in Section III (and explained in greater detail in Section VII of this testimony). Properly accounting for capacity substitutability between constrained zones and the Rest-of-Pool Capacity Zone will increase the competitiveness of the auctions: Each potential supplier in a constrained zone is competing not only with the other suppliers in that zone, but also with the marginal suppliers in the rest of the system as well. This differs significantly from the current rules, under which a resource in an import-constrained capacity zone only competes with other resources in that zone to meet the fixed requirement, and is a major design innovation of the Demand Curve Design Improvements.

V. DETAILED DESCRIPTION OF THE DEMAND CURVE DESIGN IMPROVEMENTS

A. Determining the Marginal Reliability Impact of Capacity

Q: What economic considerations must be balanced in developing demand curves for a Forward Capacity Market?

A: The Forward Capacity Market can be viewed as balancing two competing considerations. At a high level, the benefit of procuring more capacity is that it reduces energy demand that may go unserved (sometimes called "lost load"). However, procuring more capacity is costly. Capacity demand curves can be viewed as a means to make an economic choice about how this tradeoff between the costs and benefits of procuring more or less capacity should be resolved.

Q: Is it possible to measure the relationship between capacity and expected lost load?

A: Yes. Reliability planning models are used to calculate the expected lost load for a given level of installed capacity in a power system. These models calculate, among other things, a reliability performance metric known as the "expected energy not served" (also called "expected unserved energy"). Expected energy not served is measured in MWh/year and depends on, among other things, the amount of capacity installed on the system and in each constrained zone.

Expected energy not served is an informative measure of how frequently an incremental unit of capacity would help avoid lost load. Intuitively, when the system has low levels of capacity, procuring an incremental MW of capacity tends to have a big reliability benefit because it reduces lost load in many hours per year. At the opposite extreme, when the system has high levels of capacity, an incremental MW of capacity generally has little reliability benefit: it is rarely needed and reduces lost load in very few (if any) hours per year.

Q: How is the incremental impact of capacity on lost load measured?

A: The ISO's full-scale reliability planning simulation model, which is calibrated for the New England power system, can calculate the expected energy not served at any system and zonal capacity level. This model has been used for a number of years to determine the system's Installed Capacity Requirement (net of HQICCs) ("Net ICR") and each constrained capacity zone's Local Resource Adequacy Requirement or Maximum Capacity Limit. This reliability planning simulation model's data inputs are updated and vetted annually with New England stakeholders.

To determine the incremental impact of capacity on expected energy not served for each capacity level, the ISO's reliability planning simulation model can also be applied to evaluate the change in expected energy not served associated with a 1 MW increase in capacity, at each capacity level. As noted earlier in this testimony, we refer to this relationship between incremental capacity and its impact on expected energy not served as the Marginal Reliability Impact ("MRI") of capacity. The MRI of capacity is central to the construction of cost-effective capacity demand curves.

Q: What are indicative MRI values for the New England system, using current system planning parameters?

A: Figure 1 below indicates how the MRI of capacity varies in the New England system overall, across a range of capacity levels surrounding the Net ICR. The MRI values shown in Figure 1 are determined using the system planning parameters for FCA 10 (*e.g.*, the Net ICR value of 34,151 MW shown in Figure 1 applied to FCA 10).

Expected energy not served decreases with incremental system capacity. This means the system MRI values are negative numbers. For convenience, in constructing Figure 1 all of the MRI values have been first multiplied by negative one (-1) before presenting them in the graph; this merely enables the graph's origin to be located toward the lower left, as graphs are commonly represented.

The units of measurement for MRI are in hours per year. That represents the number of expected hours annually in which an increment of capacity would be used to avoid lost load (that is, the additional increment of capacity would produce energy to meet demand that would otherwise go unserved). For example, at the Net ICR value of 34,151, the MRI value is (approximately) negative 0.6. This means that, based on the ISO's reliability planning simulation model, in an unconstrained system with 34,151 MW of capacity overall, an additional 1 MW of capacity would reduce expected energy not served by 0.6 MWh annually.

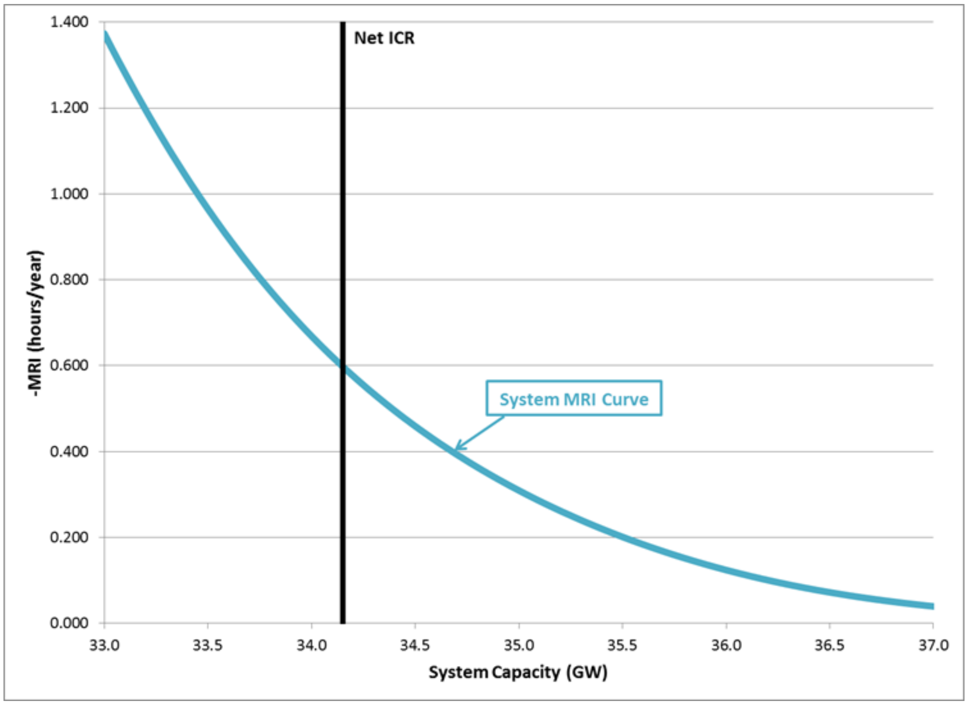

Figure 1

As a point of reference for context, using the same system planning parameters, the ISO's reliability planning simulation models indicate that at Net ICR in an unconstrained system (*i.e.*, one without any constrained capacity zones), the total expected energy not served is approximately 683 MWh/year.

Q: Why does the MRI curve have the curved, "bow-like" shape illustrated in Figure 1?

A: MRI curves have a characteristic shape. They are steep when there is relatively little capacity, and get progressively flatter as more capacity is added. The reason for this shape is simple: When there is relatively little capacity in the system, there will be many expected hours with lost load, and any further reduction in capacity has a large, adverse marginal reliability impact. In other words, when there is relatively little capacity, the curve must rise steeply as capacity falls.

In contrast, when there is ample capacity, there are few expected hours with lost load, and any additional capacity may be rarely used. Thus, at higher capacity levels, the marginal reliability impact does not change much with additional capacity so the curve becomes progressively flatter.

In economic terms, system capacity has a diminishing marginal reliability impact on expected energy not served.

Q: How does the MRI curve relate to the system's Net ICR?

A: At the Net ICR value, the marginal reliability impact of capacity does not exhibit a discrete change. Instead, the marginal reliability impact changes gradually over a broad range of system capacity levels.

There is no specific, theoretical formula for calculating the MRI value at the system's Net ICR. Instead, it must be ascertained by performing the engineering-economic analyses using reliability planning simulation models, as the ISO conducted to produce the values shown in Figure 1.

Q: Does the shape of the MRI curve confirm that vertical demand curves poorly reflect the beneficial reliability impact of incremental capacity?

A: Yes, that is correct. From an economic perspective, a vertical system demand curve inappropriately models the system as if there is a large, discrete improvement in system reliability in moving from just below, to just above, a fixed capacity requirement level. Moreover, a vertical demand curve inappropriately treats reliability as if there is no incremental reliability benefit of additional capacity above the fixed capacity requirement level.

Neither of these underpinnings of vertical demand curves is conceptually correct, as the data in Figure 1 demonstrate. Importantly, this conclusion holds not only for the system overall, but also applies when vertical demand curves are used for capacity zones – as occurs under the current rules. We explain this further in Sections V.C and V.D below.

Q: Can similar MRI curves be developed to represent the marginal reliability impact of capacity in an import- or export-constrained capacity zone?

A: Yes. The methods for calculating MRI values are conceptually similar for constrained capacity zones, but there are important additional details when MRI curves are determined for constrained capacity zones. These additional details affect both the interpretation of constrained zone demand curves and the calculation of zonal prices. These issues are discussed in detail in Sections V.C and V.D.

B. <u>Deriving a System Demand Curve Based on Capacity's Marginal Reliability Impact</u>

Q: Was the existing linear system demand curve initially designed to reflect capacity's marginal reliability impact?

A: No. As summarized in our overview provided in Section II of this testimony, the existing linear system demand curve was not developed in a manner that considered capacity's marginal reliability impact.

Q: Does the existing system demand curve therefore require modifications in order to procure capacity cost-effectively?

A: Yes. As explained in Section IV of this testimony, to satisfy the cost-effectiveness design principle, a capacity demand curve must specify prices based on capacity's MRI value. This is true for both the system demand curve (which determines the capacity price for the Rest-of-Pool Capacity Zone) as well as for each constrained capacity zone.

The Demand Curve Design Improvements therefore revise the existing linear system demand curve so that at each capacity level, it specifies a price that directly reflects the system's MRI. That is, the system-wide demand curve will be based on the system-level MRI of capacity, and the demand curves for constrained zones will be based on the MRI of capacity in each specific zone. This will enable the Forward Capacity Auction, in each constrained zone and in the Rest-of-Pool Capacity Zone, to procure capacity cost-effectively.

Q: Is it possible to procure capacity cost-effectively in constrained zones if the zones have MRI-based demand curves, and the existing linear system demand curve is retained?

A: No. With sloped capacity demand curves, the amount of capacity procured in each zone (including the Rest-of-Pool Capacity Zone) is interdependent. That is, the amount procured in a constrained zone depends on the price and quantity cleared in the Rest-of-Pool Capacity Zone, and vice versa. (We discuss interdependent clearing in detail in Section VII below.) Because of this, the cost-effectiveness principle will be satisfied only if *all* of the capacity demand curves are based on the marginal reliability impact of capacity – including the system-wide demand curve.

Additional, detailed explanations of the ISO's concerns if the existing system-wide demand curve is retained are provided on in Section VI and on pages 15-18 of the ISO's Technical Memorandum, included in this filing as Attachment 2.

Q: How is the MRI curve presented in Figure 1 translated into a sloped system demand curve consistent with the cost-effectiveness design principle?

A: As explained in Section IV, a demand curve must specify a price at each capacity level that is proportional to its MRI value to procure capacity cost-effectively. This is done by multiplying the MRI value at each capacity level by a conversion factor (*i.e.,* a number) to calculate a demand curve's price at each capacity level. This conversion factor is also called a "scaling factor," as it can be interpreted as proportionally changing the scale (*i.e.,* the units on the vertical axis) in any graphical representation of an MRI curve.

Capacity demand curves specify price in terms of dollars per MW-year (and may be expressed in dollars per kW-month). The scaling factor converts the MRI values (in hours per year) into prices (in dollars per MW-year). The scaling factor is therefore measured in of dollars per MWh.

Q: How do you interpret the scaling factor? Does it have an economic meaning?

A: Mechanically, a large value of the scaling factor will produce "richer" demand curves that tend to procure a great deal of capacity, resulting in lower levels of expected energy not served. A small value of the scaling factor would result in the FCA procuring less capacity, though how much less will depend on the offer prices of capacity suppliers.

In economic terms, the scaling factor can also be interpreted as an implied "cost" associated with each MWh of unserved energy. This implied cost is not based on consumers' marginal value of energy. Rather, it is the revealed marginal cost that society incurs to avoid lost load (per MWh of avoided lost load) when the FCM procures sufficient capacity (at a price of Net CONE) to satisfy the region's "1-day-in-10" Loss of Load Expectation reliability planning objective.

Q: Please explain further.

A: As a general matter, the ISO does not propose here to assume the marginal value that consumers place on energy (or, in this context, on the cost a consumer may incur due to unserved energy). Rather, the ISO will *derive* (not assume) a value for the scaling factor that is (just) high enough to satisfy the reliability and sustainability design principles introduced in Section IV. In that way, the scaling factor will be set at the level (just) high enough to produce outcomes consistent with the resource adequacy planning objective and to induce new entry when needed.

A more detailed technical interpretation of the scaling factor in demand system modeling, which can also be viewed as a "penalty factor" on expected energy not served, is provided on pages 3-6 of Attachment 2, Technical Memorandum (addressing the "Economic Foundations" of capacity demand curves).

Q: How is the value of the scaling factor determined, procedurally?

A: Under the Demand Curve Design Improvements, the capacity demand curves will use the smallest value of the scaling factor that satisfies the reliability and sustainability design principles. By doing so, constructing capacity demand curves as the product of the MRI curves and this scaling factor will satisfy all three of the central design principles presented previously in Section IV.

More specifically, the scaling factor is calculated as the ratio of Net CONE and the system's MRI value evaluated at the Net ICR capacity level. In this way, the system demand curve will specify a price of Net CONE when the level of capacity procured is (just) enough to meet the region's "1-day-in-10" Loss of Load Expectation resource adequacy objective.

Q: Can you explain the effect of the scaling factor on the system demand curve graphically?

A: Yes. Figure 2 below illustrates the effect of the scaling factor graphically. Working at a conceptual level, the left panel shows a (hypothetical) system MRI curve and the right panel shows the corresponding system demand curves associated with various scaling factor values.

There are three hypothetical system demand curves shown in the right panel. The "too high" scaling factor produces the uppermost (red color) demand curve, which would specify a price above Net CONE at the Net ICR capacity level. That demand curve would procure more capacity than necessary to meet the region's resource adequacy objective at a price of Net CONE (or, equivalently, it would remunerate capacity at a rate above Net CONE when the capacity level just satisfies the resource adequacy objective).

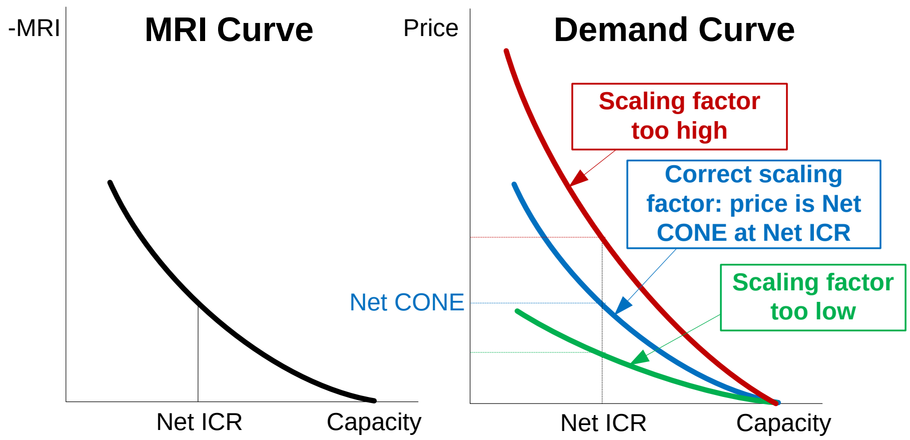

Figure 2

The “too low” scaling factor produces the lowermost (green color) demand curve, which would specify a price below Net CONE at the Net ICR capacity level. That demand curve would not satisfy the reliability and sustainability design principles because it does not procure sufficient capacity to meet the resource adequacy objective at Net CONE (*viz.*, the estimated price necessary to induce entry).

The correct scaling factor produces the middle (blue color) demand curve, which would specify a price of Net CONE at the Net ICR capacity level.

Note that each of these three hypothetical demand curves sets price proportional to the MRI curve. Thus, each of these three demand curves would satisfy the cost-effectiveness design principle. However, only the middle and the uppermost demand curves will also simultaneously satisfy the reliability and sustainability principles. The Demand Curve Design Improvements set the scaling factor in a manner corresponding to the middle (blue color) demand curve, which is just high enough to satisfy the Net ICR on average and to induce new entry when necessary. The uppermost (red color) demand curve would also satisfy all three central design principles, but would procure more capacity than necessary to meet the reliability standard and have a higher total cost.

Q: Please explain further why determining the scaling factor in this way is appropriate. Is this calculation consistent with expected offer behavior and the ISO's calculation of Net CONE more generally?

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

This equilibrium is a property of the ISO's two-settlement capacity market design (also known as Pay for Performance). Under the two-settlement capacity market design, an offer price of Net CONE is more consistent with the economics of competitive capacity supply pricing than is the historical bidding behavior of capacity suppliers, which was generally governed by their so-called 'going forward' (or avoidable) capital costs.

In addition, the assumption that the equilibrium capacity price reflects Net CONE is also consistent with the cash-flow and pricing calculations actually employed in the ISO's discounted cash-flow models used to estimate Net CONE for the New England system.

Taken together, the proposed method to set the demand curves' scaling factor is internally consistent with both the FCM's two-settlement capacity market design, as well as the specific pricing assumptions used to calculate estimated Net CONE.

Q: Is the value of the scaling factor the same for both the system-wide demand curve and the constrained zones' demand curves?

A: Yes. The same scaling factor is used to convert the MRI curves into demand curves for the system and for each constrained zone. (That is, the MRI curves are different for each zone, but the scaling factor is the same). To do otherwise would imply the region is willing to incur a higher implicit "cost" to avoiding lost load in one area of New England than in another. The ISO has no empirical evidence to justify placing a higher value on avoiding a MWh of lost load in one area of the system than in another.

Q: Why is the scaling factor set based on the system-level MRI curve, rather than the MRI curves for the constrained zones?

A: In specifying the scaling factor as the ratio of Net CONE to the MRI of capacity at Net ICR, the scaling factor is calculated using the system-level MRI values rather than the MRI curves for constrained zones. Although not immediately obvious, this is appropriate because the estimated Net CONE in New England is the same in both constrained zones and in the Rest-of-Pool Capacity Zone.

To explain further, consider first what a common Net CONE value in all areas of the system implies for prices. Conceptually, if Net CONE is the same in all areas of the system, then in equilibrium there will be no price separation between zones. The reason is simple: Over time, in any zone with a higher capacity price than Net CONE, entry would occur (at Net CONE) and drive down prices in the higher-price zone – thus returning prices to Net CONE, over time, and ensuring price parity across zones.

Next, consider what price parity across zones implies for the MRI values. If there is no price separation across zones, then each zone will procure capacity at the same MRI value. This is a consequence of procuring capacity cost-effectively again: As discussed in Section IV, demand curves that satisfy the cost-effectiveness principle will procure capacity levels so that the ratio of the incremental cost of capacity (*i.e.*, price) to the incremental reliability impact of capacity (*i.e.*, MRI value) is the same in every zone.

Last, note that if the ratio of price to the MRI value is the same in every zone, then *any* zone can be used to determine the required factor of proportionality – *i.e.*, the scaling factor – between them. In other words, at the equilibrium capacity levels that (just) satisfy the reliability and sustainability principles, the ratio of price to MRI in each zone would yield the same value of the scaling factor no matter which zone's values are used. Ergo, we use the system's MRI of capacity, as a matter of practical convenience.

As a technical matter, this logic rests – at root – on the empirical validity of a common Net CONE in all areas of the system. However, the general theory of MRI-based demand curves – and their ability to satisfy the three central design principles – would continue to apply even if, at some point in the future, the ISO determined that Net CONE is higher in some zones of the system than in others. In that case, there is a generalized method for determining the appropriate scaling factor, addressed on pages 26-27 of the ISO's Technical Memorandum. This is not applicable to New England presently, however, as the ISO's Tariff specifies a single value of Net CONE.[9]

Q: Please provide an indicative MRI-based system demand curve, using a recent capacity auction's system planning parameters.

A: Figure 3 below shows the MRI-based system demand curve, constructed using the system planning parameters and Net CONE value that were applicable for FCA 10. In this auction, Net CONE was equal to $10.81/kW-month and Net ICR was 34,151 MW.

[9] *See* ISO Tariff Section III.13.2.4.

For reference, Figure 3 also depicts the existing linear system demand curve, shown as a dashed line. The existing linear system demand curve is to the right of the MRI-based curve at most price levels.

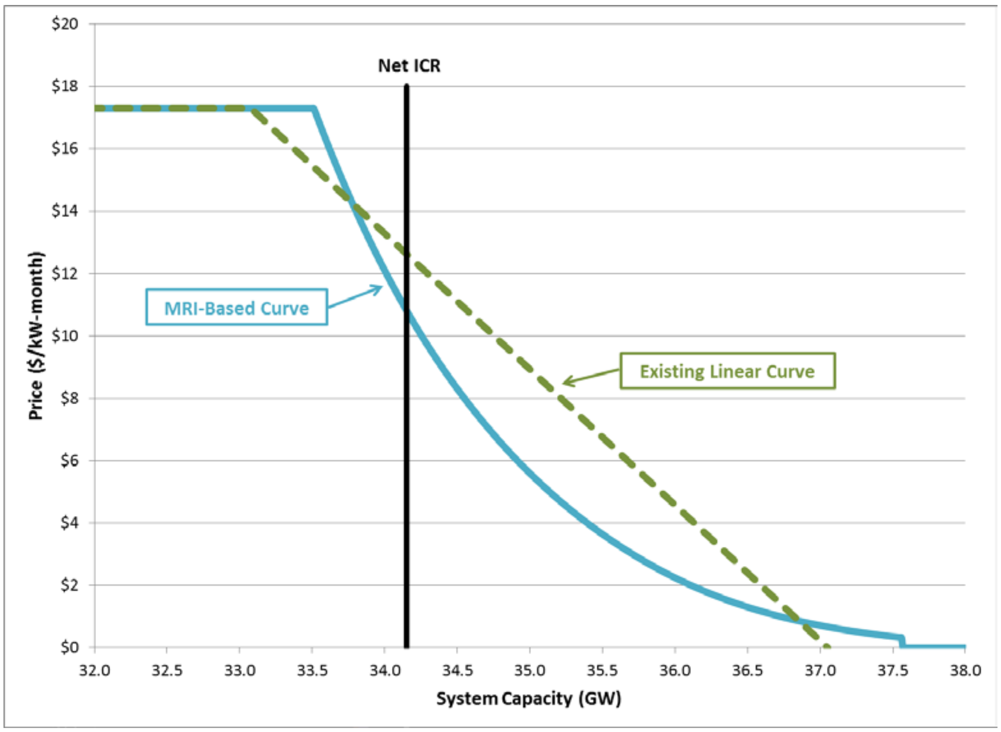

Figure 3

Note that the maximum capacity price for FCA 10 was set at 1.6 times Net CONE, based on current rules. This is represented in Figure 3 by the horizontal segment at a price of $17.296/kW-month. The Demand Curve Design Improvements do not change the rules governing the determination of this maximum capacity price (also known as the FCA Starting Price). In addition, the slight "drop" in the curve evident just above the 37.5 GW level at the far right of

Figure 3 is due to the truncation rules used to administer the auction; this detail is explained in Section X.B further below.

Q: Would a demand curve design that retains this linear system demand curve satisfy the three central design principles?

A: No. The existing linear system demand curve was designed to satisfy the reliability and sustainability design principles, but it does not satisfy the cost-effectiveness principle because it does not specify prices proportionate to the marginal reliability impact of capacity.

Q: Will the MRI-based system demand curve satisfy the three central design principles?

A: Yes. Because it specifies a price of Net CONE at the Net ICR capacity quantity, the MRI-based curve satisfies the reliability and sustainability design principles. Furthermore, because the curve specifies prices that are proportional to the MRI of capacity at all quantities, the MRI-based system demand curve will produce cost-effective outcomes when used in concert with similar MRI-based zonal demand curves.

We address these zonal demand curves next.

C. Demand Curves for Import-Constrained Capacity Zones

Q: Is the methodology used to determine MRI values for import-constrained zones similar to that used at the system level?

A: Broadly, yes. The sloped demand curves for import-constrained capacity zones are based on the MRI of capacity in the import-constrained zone. As before, the Demand Curve Design Improvements calculate zone-specific MRI values for a range of zonal capacity levels, producing an MRI curve specific to each constrained zone.

There are some differences between how MRI values are calculated for the system and for a constrained zone, however. These differences affect the precise interpretation of the zonal demand curves, and how they determine zonal prices.

Q: How are the MRI values calculated for a constrained capacity zone?

A: For an import-constrained capacity zone, the MRI values are calculated based on the *additional* reduction in expected energy not served when incremental capacity is procured on the constrained side of a zonal interface, rather than in the unconstrained (Rest-of-Pool Capacity Zone) side. This is logical because the additional demand for capacity in an import-constrained zone – above and beyond the demand for capacity in the system overall – should be based on the additional reliability improvement from procuring capacity in the constrained zone.

Specifically, the MRI values for an import-constrained zone represent the reduction in expected energy not served if 1 MW more capacity is procured in the constrained zone, and *simultaneously* 1 MW less capacity is procured in the Rest-of-Pool Capacity Zone. In effect, the MRI values for a constrained zone can be interpreted of as the incremental reliability impact of “transferring” (or substituting) a MW of capacity across the zonal interface, while holding the total system capacity constant. (We use the term “transferring” here and throughout as a simple shorthand for the reliability impact of procuring 1 more MW in one zone, and procuring 1 MW less in another – that MW of capacity is not *literally* transferred from one zone to another, of course).

We calculate the MRI values for constrained zones this way for an important reason: They reveal the beneficial reliability impact of procuring incremental capacity on one side of a zonal interface, *relative to* the impact of procuring incremental capacity on the other (Rest-of-Pool Capacity Zone) side of the interface. This will enable the demand curve for the constrained capacity zone to appropriately and easily determine the *additional* amount that should be paid to capacity located on the constrained side of a transmission interface – that is, in addition to the price paid to the Rest-of-Pool Capacity Zone.

A more technical presentation of the engineering-economic basis for how MRI values are calculated for import-constrained zones is provided on pages 7-11 of Attachment 2, the ISO’s Technical Memorandum.

Q: Are there any additional system parameters or modeling assumptions necessary to calculate the MRI curves for an import-constrained zone?

A: Yes. There are two. The first is that the zonal MRI-based curves are calculated assuming total system capacity is equal to Net ICR. This assumption is consistent with how the ISO currently determines the Local Resource Adequacy requirement for import-constrained zones,[10] and consistent with the level of capacity in the system overall at the intended equilibrium of the Forward Capacity Market.

Second, the MRI values for constrained capacity zones depend on the capacity transfer capability across the zonal interface. This capability is determined based on engineering and reliability considerations, including various specific transmission line and resource outage conditions. The specific capacity transfer capability assumptions for zonal interfaces that are used by the ISO to calculate MRI values for constrained capacity zones are explained in the accompanying Testimony of Alan McBride, the ISO's Director of Transmission Strategy and Services (the "McBride Testimony").

Q: Please provide an indicative MRI curve for an import-constrained capacity zone.

A: In FCA 10, Southeast New England ("SENE") was modeled as an import-constrained capacity zone. In FCA 10, the SENE zone had a vertical demand

[10] *See* ISO Tariff Section III.12.2.1.1.

curve with a fixed Local Sourcing Requirement ("LSR") of 10,028 MW. Figure 4 below illustrates the indicative MRI values for this capacity zone, calculated using the ISO's reliability planning simulation system and parameters applicable to FCA 10.

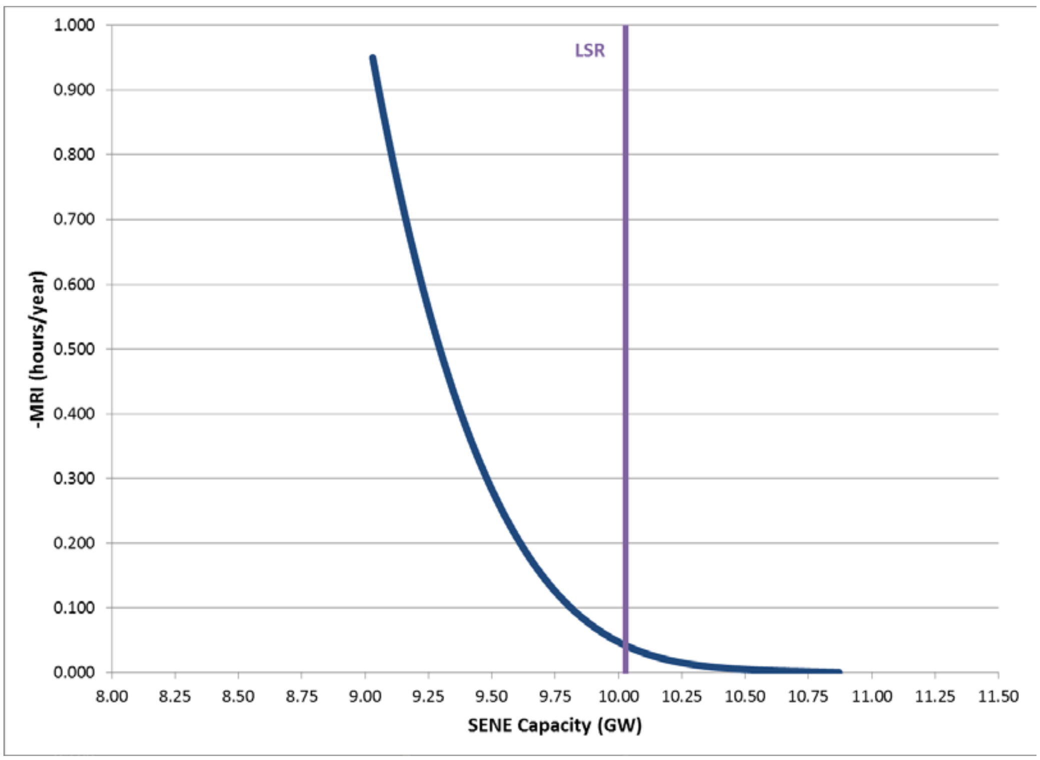

Figure 4

The MRI values shown in this figure represent the additional reduction in expected energy not served if 1 MW more is procured in the SENE capacity zone, and 1 MW less is procured in the Rest-of-Pool Capacity Zone. (Note, as with the system MRI figure shown previously, for convenience the MRI values have been multiplied by negative one (-1) before depicting the curve in Figure 4).

For example, the figure indicates that at the LSR capacity level, the MRI value is (approximately) negative .04 hours/year. That means if an incremental MW of capacity is procured in the SENE zone, *instead* of procuring it in the Rest-of-Pool Capacity Zone, that MW of capacity would yield a (slightly) greater reduction in expected energy not served.

Q: Please interpret the MRI values in Figure 4.

A: To put these numbers in perspective, recall that (as discussed in Section V.A above) the MRI of procuring an additional MW of capacity in the unconstrained areas of the system, when the system is at Net ICR, is (approximately) negative 0.60 hours/year. At the LSR capacity level, the zonal MRI value is (approximately) negative 0.04. Thus, adding an incremental MW of capacity when at LSR in the import-constrained zone, if the total system capacity is <u>not</u> held constant (so that total system capacity also increases by 1 MW), would reduce total expected energy not served by a total of 0.60 + 0.04 = 0.64 hours/year.

The figure also reveals that as the import-constrained zone moves from being below to above the existing Local Sourcing Requirement capacity level, the zonal reliability impact values decline gradually. When it reaches approximately zero, at above 10.75 GW of zonal capacity, procuring incremental capacity in the zone provides no discernable additional reliability benefit (in terms of reducing expected energy not served) relative to procuring incremental capacity in the Rest-of-Pool Capacity Zone.

Q: Please explain the shape of the MRI curve for this import-constrained capacity zone.

A: Figure 4 shows that when there is less capacity than approximately 10.75 GW in this particular capacity zone, procuring incremental capacity inside the constrained zone has a more beneficial reliability impact than procuring incremental capacity in the Rest-of-Pool Capacity Zone. Fundamentally, this occurs because under some load conditions, the zone's interface limit is binding so incremental capacity in the Rest-of-Pool Capacity Zone cannot deliver energy to help avoid lost load within the constrained zone. Procuring the incremental capacity within the constrained zone would help to avoid lost load within the constrained zone, however.

When there is a high level of capacity located within an import-constrained zone, lost load within the zone is less frequent and the zonal MRI values become close to zero. When there is little capacity located in the import-constrained zone, these conditions will occur more frequently, and the zonal MRI values become much greater (in magnitude). Thus, the MRI curve for an import constrained zone will characteristically become steeper as capacity falls below the traditional Local Sourcing Requirement and the MRI curve become progressively flatter at higher capacity levels.

Q: How does the MRI curve for an import-constrained zone relate to the zone's current vertical demand curve, at the Local Sourcing Requirement?

A: In general, there is no specific, theoretical formula for calculating the MRI value at the zone's Local Sourcing Requirement capacity level. Instead, the MRI values must be ascertained by performing the engineering-economic analyses using reliability planning simulation models, as the ISO conducted to produce the values shown in Figure 4.

As with the system MRI curve, the zonal MRI curve does not exhibit a discrete change in MRI values at the Local Sourcing Requirement. Instead, Figure 4 demonstrates that the effect on expected energy not served of procuring incremental capacity in the import-constrained zone, rather than procuring it in the Rest-of-Pool Capacity Zone, changes gradually over a broad range of zonal capacity levels. This reveals, in visual form, why using fixed capacity requirements (vertical demand curves) in constrained capacity zones is fundamentally inconsistent with the impact of incremental capacity on system reliability.

Q: How is the zonal MRI curve translated into a zonal demand curve?

A: To translate a constrained capacity zone's MRI curve into a sloped zonal demand curve, we use the same principles and procedures applied to the system MRI curve. That is, we multiply the zonal MRI value by the scaling factor to calculate the zonal demand curve's price at each zonal capacity level.

Q: Please provide an indicative zonal demand curve for the Southeast New England import-constrained zone.

A: Figure 5 below presents the indicative zonal demand curve for the Southeast New England capacity zone, calculated using the scaling factor and indicative zonal MRI values applicable to the FCA 10 system.

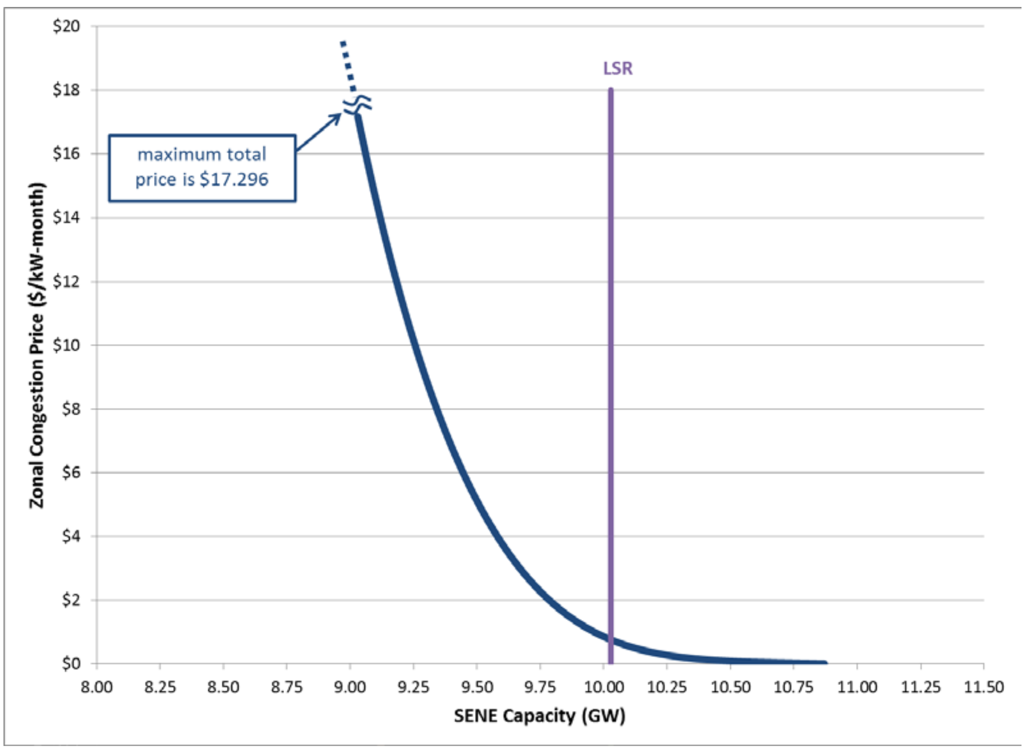

Figure 5

Q: What is the interpretation of the price specified at each capacity level in Figure 5?

A: The prices specified by an MRI-based zonal demand curve have a slightly different interpretation than the prices for the system's MRI-based demand curve. The prices specified by the zonal demand curve represent the "congestion" component of the total capacity price paid to resources in that zone. That is, the demand curve for an import constrained zone specifies a price premium paid to resources in the import constrained zone, on top of the system capacity price paid to resources in the Rest-of-Pool Capacity Zone.

For example, imagine (hypothetically) that in the FCA, 9.75 GW of capacity were procured in this import-constrained capacity zone. At this capacity level, the zonal demand curve specifies a price of (approximately) $2.25/kW-month. Because this value represents the congestion component of the clearing price in the zone, resources in this zone would be paid the sum of (a) the price determined by the MRI-based system-wide demand curve, and (b) the $2.25/kW-month zonal price premium specified by the MRI-based zonal demand curve.

Q: What is the price premium associated with the Local Sourcing Requirement?

A: The price premium specified by the demand curve for the Southeast New England Capacity Zone at its Local Sourcing Requirement of 10,028 MW is $0.77/kW-month. If the zone cleared at this capacity level, resources in the zone would receive a \$0.77/kW-month premium paid on top of the capacity clearing price paid to resources in the Rest-of-Pool Capacity Zone.

As with the zone's MRI curve, the price changes gradually as the zone's capacity level moves from just below, to just above, the Local Sourcing Requirement. Fundamentally, this reflects that the reliability impact of incremental zonal capacity (relative to incremental capacity in the Rest-of-Pool Capacity Zone) also changes gradually in this range.

Q: Why is it appropriate to interpret the prices specified by an MRI-based zonal demand curve as determining a price premium, or 'congestion' price, to pay to resources in that zone?

A: The interpretation of a MRI-based zonal demand curve in terms of congestion pricing is based on sound economics, and is a direct consequence of how the import-zone MRI values are being calculated.

Specifically, the zonal MRI values represent the change in expected energy not served if we *substitute* (or "transfer") one unit of capacity out of the Rest-of-Pool Capacity Zone and into the import-constrained zone. Substituting capacity from the Rest-of-Pool Capacity Zone into an import-constrained zone has a net reliability benefit, in general, because it helps reduce expected energy not served within the constrained zone when the zonal interface is binding – when incremental capacity located in the Rest-of-Pool Capacity Zone would not help to reduce the expected energy not served within the constrained zone.

In other words, a zonal demand curve based on the zonal MRI of capacity tells us how much more 1 MW of additional capacity is worth if procured in the import-constrained zone, *instead of* being procured in the Rest-of-Pool Capacity Zone. That is, it indicates what the price *difference* should be between the import-constrained zone and the Rest-of-Pool Capacity Zone. This price difference across a constrained interface is, of course, what we normally call the congestion price.

Q: How is a demand curve for an import-constrained zone that specifies a congestion price used to determine the total cleared capacity in this zone?

A: In general, the process of clearing the FCA and determining clearing prices and quantities in each capacity zone is conducted simultaneously and interdependently, in accordance with the Tariff's rules governing the ISO's descending clock auction format.[11] However, the central concepts of how prices and capacity levels are determined for a constrained zone can be illustrated simply.

Imagine, for a moment, that at the level of capacity cleared in the system overall, the MRI-based system demand curve specifies a price of $8.00/kW-month. One

[11] *See* ISO Tariff Section 13.2.3 *et seq.*

can conceptualize the determination of the price and cleared capacity in an import constrained zone by viewing the zonal demand curve as specifying the additional price (*viz.*, additional to $8.00/kW-month) applicable to cleared capacity in the zone. That is, think of the "total price" for the import constrained zone as being determined by the "congestion price" demand curve discussed earlier *plus* the clearing price in the Rest-of-Pool Capacity Zone.

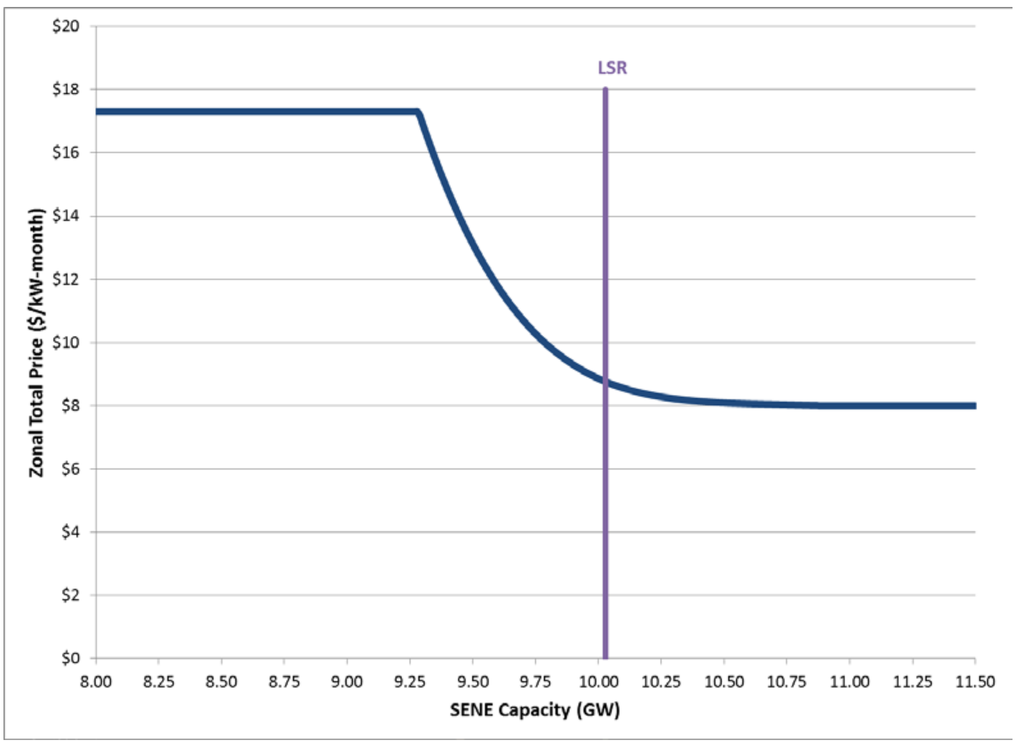

Figure 6

Visually, Figure 6 illustrates this conceptual "total price" demand curve logic, for the Southeast New England Capacity Zone, again assuming the price paid in the Rest-of-Pool Capacity Zone is $8.00/kW-month. The curve in Figure 6 is based on the zone's congestion-price demand curve provided in Figure 5, except that in

Figure 6 it has been “shifted up” by $8.00/kW-month at all quantities. (The curve also depicts the FCA’s maximum price of 1.6 times Net CONE, represented by the horizontal segment at $17.296/kW-month.)

The upward shift of this conceptual “total price” demand curve reflects the fact that the total price paid at each zonal quantity is equal to the sum of the price paid in the Rest-of-Pool Capacity Zone and the congestion price at this zonal quantity, where the latter is determined by the zone’s MRI-based congestion-price demand curve.

As an example, recall that in Figure 5 previously, the congestion price at a zonal capacity level of 9.75 GW is (approximately) $2.25/kW-month. The total price paid to resources in the zone, in that situation, would be the sum of $2.25/kW-month and the price specified by the system-wide demand curve. If the latter equals $8.00/kW-month as assumed in constructing Figure 6, then the total price paid to resources in this import-constrained zone can be read directly from Figure 6: At a zonal capacity level of 9.75 GW, the total price would be $8.00 + $2.25 = $10.25/kW-month.

Q: Is this “total price” demand curve a literal description of how the ISO clears the forward capacity auction?

A: No. This is a conceptual representation, intended to convey how the price specified by the system-wide demand curve and an MRI-based zonal demand curve (which specifies congestion prices) jointly determine the clearing price in the zone.

In practice, the ISO uses sophisticated software during (and after) the Descending Clock Auction to determine the cleared prices and quantities in each capacity zone. This is necessary to account for the interdependence of the cleared quantities in each zone. That is, in the process of determining the zonal cleared quantity, one cannot hold the price in the Rest-of-Pool Capacity Zone constant (as we assumed, for simplicity, in interpreting Figure 6); in general, clearing an additional MW in an import zone will also clear another MW in the system overall, which may change the price in the Rest-of-Pool Capacity Zone. The procedures used in practice to clear the FCA properly account for these interdependencies. We discuss the clearing logic that accounts for these interdependencies in more detail in Section VII.

Q: Figure 6 implies that the price in an import-constrained zone cannot be less than the price in the rest-of-pool zone. Is that correct?

A: Yes. As Figure 6 indicates, at low zonal quantities, the total price paid to resources in an import-constrained zone will reflect the Rest-of-Pool Capacity Zone price plus a potentially high zonal congestion price; the high zonal congestion price is a locational price signal that indicates to investors the high reliability improvement associated with providing incremental capacity in the import-constrained zone, relative to the Rest-of-Pool Capacity Zone.

In contrast, when the zone has a large amount of capacity, the congestion price will tend to be close (or equal) to zero, because providing incremental capacity in the import-constrained capacity zone has a similar (or equal) reliability benefit as in the Rest-of-Pool Capacity Zone. Even in such cases, however, the clearing price for an import-constrained zone cannot fall below the clearing price for the Rest-of-Pool Capacity Zone.

Q: In summary, are the system and zonal locational price signals based on the system and zonal MRI-based demand curves consistent with the relative reliability impacts of supplying incremental capacity in each zone?

A: Yes. With respect to the incremental reliability impacts, one can think of the incremental reliability impact of supplying a MW of capacity in an import-constrained zone as the sum of two components: (1) the incremental reliability impact of supplying a MW of capacity in the Rest-of-Pool Capacity Zone, and; (2) the *additional* reliability impact of then "transferring" this MW of capacity from the Rest-of-Pool Capacity Zone into the import-constrained zone. Both of these beneficial reliability impacts are captured with the Demand Curve Design Improvements. The first component is fully reflected in the system price paid to resources in the Rest-of-Pool Capacity Zone, as specified by the MRI-based system demand curve. The second component is fully reflected in the *additional* price paid to resources in the import-constrained zone, as specified by the MRI-based zonal demand curve. In this way, the system and zonal locational price signals are fully consistent with the relative reliability impacts of supplying incremental capacity in each zone.

D. <u>Demand Curve for Export-Constrained Zones</u>

Q: Is the methodology used to determine the MRI curves for export-constrained zones similar to that used for import-constrained zones?

A: Yes. The MRI curves for export-constrained zones are derived using the same approach as for import-constrained zones. As with import-constrained zones, the Demand Curve Design Improvements calculate zone-specific MRI values for a range of zonal capacity levels, producing an MRI curve specific to each export-constrained zone.

Q: How are the MRI values calculated for an export-constrained capacity zone?

A: For an export-constrained capacity zone, the MRI values are calculated based on the additional expected energy not served when incremental capacity is procured in the export-constrained zone, rather than in the Rest-of-Pool Capacity Zone. This is logical because the demand for capacity in an export-constrained zone – relative to the demand for capacity in the system overall – should be based on the (potentially) *lower* level of reliability when capacity is procured within an export-constrained zone.

As with import-constrained zones, the MRI values for an export-constrained zone represent the change in expected energy not served if 1 MW more capacity is procured in the constrained zone, and simultaneously 1 MW less capacity is procured in the Rest-of-Pool Capacity Zone. In effect, the MRI values for a constrained zone represent the incremental reliability impact of “transferring” (or substituting) a MW of capacity across the zonal interface, while holding the total system capacity constant.

The MRI calculations for export-constrained zones requires information about the capacity level in the system overall, and the capacity transfer limits across the zonal interface. As with import-constrained zones, the zonal MRI-based curves for export-constrained zones are calculated assuming total system capacity is equal to Net ICR. This assumption is consistent with how the ISO currently determines the Maximum Capacity Limit for export-constrained zones,[12] and consistent with the level of capacity in the system overall at the intended equilibrium of the Forward Capacity Market.

The specific capacity transfer capability calculations for export-zone interfaces differ somewhat from those applied to import-zone interfaces. The applicable capacity transfer capability assumptions are explained the accompanying McBride Testimony.

[12] *See* ISO Tariff Section III.12.2.2.

A more technical presentation of the engineering-economic basis for how MRI values are calculated for export-constrained zones is provided on pages 12-14 of the ISO's Technical Memorandum.

Q: Is the interpretation of the MRI values calculated for an export-constrained zone consistent with those derived for an import-constrained zone?

A: Yes. For both import- and export-constrained capacity zones, the zonal MRI values represent the incremental reliability impact of transferring a MW of capacity from the Rest-of-Pool Capacity Zone into the constrained capacity zone. However, unlike with import-constrained zones, transferring capacity from the Rest-of-Pool Capacity Zone into an export-constrained zone will tend to worsen system reliability (that is, to increase expected energy not served overall). As a result, the MRI values for an export-constrained zone will have the opposite sign of the MRI values for an import-constrained zone.

Q: Please provide an indicative MRI curve for an export-constrained capacity zone.

A: Northern New England ("NNE") was studied as a potential export-constrained capacity zone, with an indicative Maximum Capacity Limit ("MCL") of 8,830 MW. This zone was not modeled in FCA 10. Figure 7 below illustrates the indicative MRI values for this potential export-constrained capacity zone, calculated using the ISO's current reliability planning simulation models and parameters.

The MRI values shown in this figure represent the change in expected energy not served if 1 MW more is procured in a potential Northern New England export-constrained capacity zone, and simultaneously 1 MW less is procured in the Rest-of-Pool Capacity Zone.   Note that MRI values are positive for an export-constrained zone, because expected energy not served increases (worse reliability) if capacity is transferred to the export-constrained zone from the Rest-of-Pool Capacity Zone. (For consistency with the MRI figures shown previously, the MRI values have been multiplied by negative one (-1) before depicting the curve in Figure 7; thus, the MRI curve in Figure 7 is below the x-axis.)

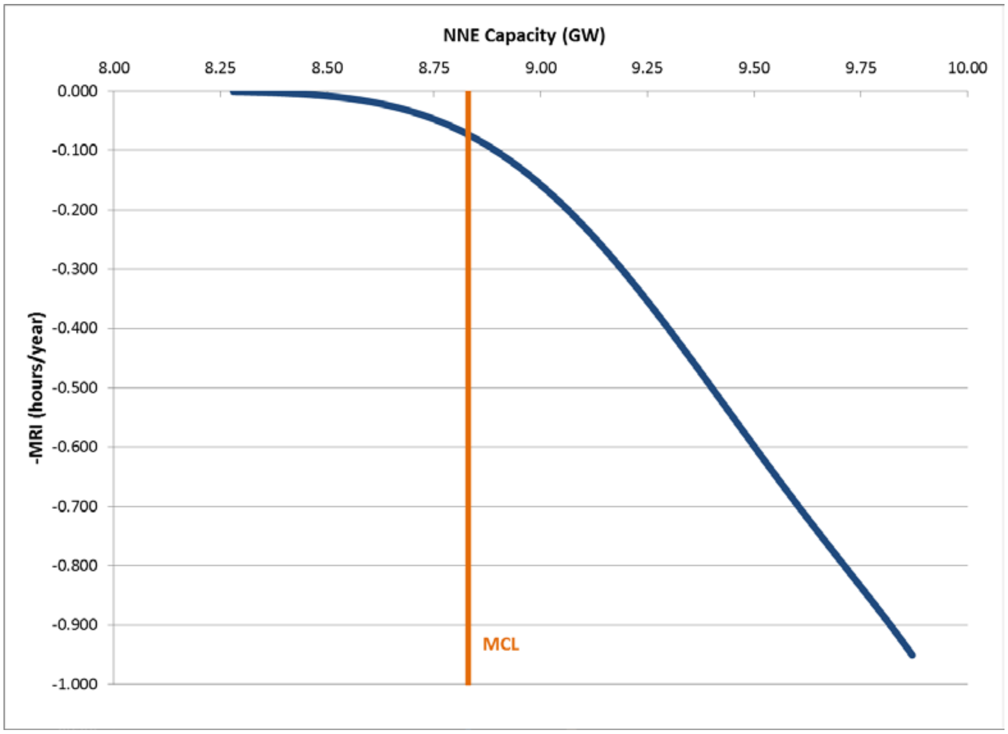

Figure 7

For example, the figure indicates that at the MCL capacity level of 8,830 MW, the MRI value is (approximately) 0.07 hours/year. That means if an incremental MW of capacity is procured in the potential Northern New England export-constrained zone, *instead* of procuring it in the Rest-of-Pool Capacity Zone, it would slightly worsen reliability (*i.e.*, increase expected energy not served).

Q: Please interpret the MRI values in Figure 7.

A: To put these numbers in perspective, recall that (as discussed in Section V.A above) the MRI of procuring an additional MW of capacity in the unconstrained areas of the system, when the system is at Net ICR, is (approximately) negative 0.60 hours/year. At the MCL capacity level, the zonal MRI value is (approximately) 0.07 hour/year. Thus, adding an incremental MW in the export-constrained zone, if the total system capacity is <u>not</u> held constant (so that total system capacity also increases by 1 MW), would reduce expected energy not served by a total of 0.60 – 0.07 = 0.53 hours/year (*i.e.*, less than the .6 hours/year reduction if the capacity was added to the Rest-of-Pool Capacity Zone). In other words, adding another increment of capacity in the export-constrained zone (beyond the MCL) helps reliability, and by (slightly) less than if the increment of capacity was added in the Rest-of-Pool Capacity Zone.

The figure also reveals that as the export-constrained zone moves from being just below to just above the existing Maximum Capacity Limit, the zonal MRI values change gradually. When the zonal MRI values are approximately zero, applicable when there is approximately 8.25 GW or less zonal capacity, procuring incremental capacity in the zone provides no discernably worse reliability impact (in terms of expected energy not served) than to procuring incremental capacity in the Rest-of-Pool Capacity Zone.

Q: Please explain the shape of the MRI curve for this export-constrained capacity zone.

A: This shape reflects that when capacity levels in the zone are low, there is little reliability impact associated with transferring a MW of capacity from the Rest-of-Pool Capacity Zone to the export-constrained zone, so the curve is flat a low zonal capacity levels. However, as more capacity is transferred into the export-constrained zone, the frequency with which the zonal interface will bind increases (rendering the energy provided by capacity in the export zone not helpful for avoiding lost load elsewhere in the system). As a result, at higher zonal capacity levels the curve gradually becomes steeper.

Q: How does the MRI curve for an export-constrained zone relate to the current vertical "demand" curve, set at the Maximum Capacity Limit?

A: In general, there is no specific, theoretical formula for calculating the MRI value at the zone's Maximum Capacity Limit. Instead, the MRI values must be ascertained by performing the engineering-economic analyses using reliability planning simulation models, as the ISO conducted to produce the values shown in Figure 7.

As seen in Figure 7, there is not a discrete change in MRI values at the Maximum Capacity Limit. Instead, the effect on expected energy not served of procuring incremental capacity in the export-constrained zone, rather than procuring it in the Rest-of-Pool Capacity Zone, changes gradually over a broad range of zonal capacity levels. As with import-constrained zones, this analysis again reveals, in visual form, why using fixed capacity requirements (vertical demand curves) in constrained capacity zones is fundamentally inconsistent with the impact of incremental capacity on system reliability.

Q: How is this zonal MRI curve translated into a demand curve?

A: To translate a constrained capacity zone's MRI curve into a sloped zonal demand curve, we use the same principles and procedures applied to the system MRI curve. That is, we multiply the zonal MRI value by the scaling factor to calculate the zonal demand curve's price at each zonal capacity level.

Q: Please provide an indicative export-constrained zonal demand curve.

A: Figure 8 below presents an indicative demand curve for the Northern New England capacity zone, calculated using the scaling factor and indicative zonal MRI values applicable to the FCA 10 system.

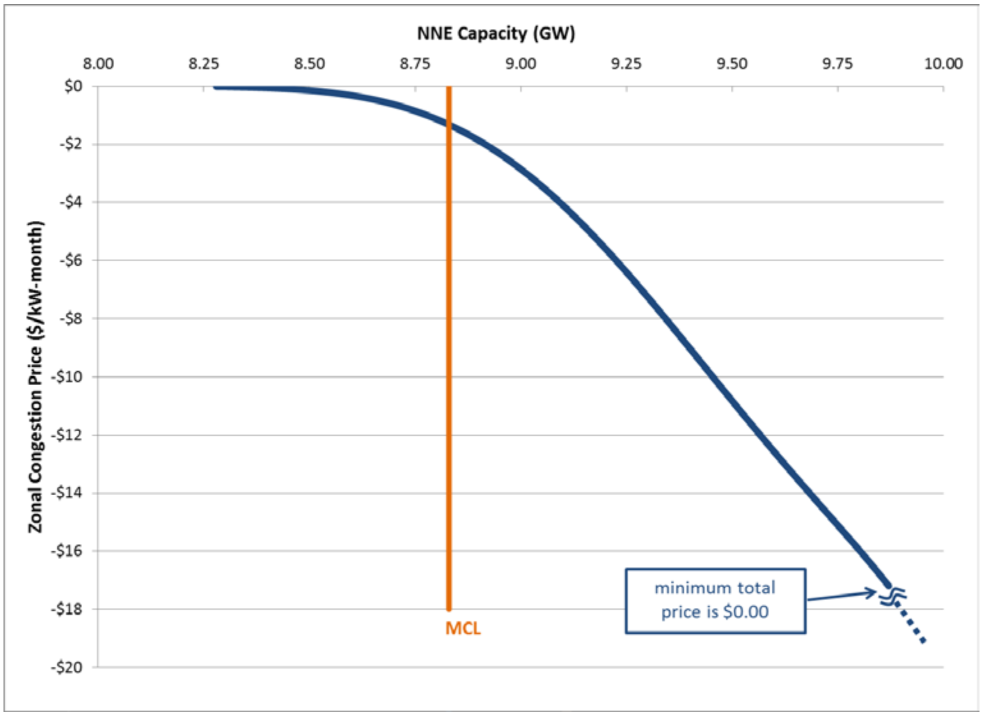

Figure 8

Q: What is the interpretation of the price specified at each capacity level in Figure 8?

A: As with an import-constrained zone, the prices specified by an MRI-based zonal demand curve have a slightly different interpretation than the prices for the system's MRI-based demand curve. The prices specified by the zonal demand curve represent the 'congestion' component of the total capacity price paid to resources in that zone. That is, the demand curve for an export constrained zone specifies a price discount to resources in the export-constrained zone – resources in the export-constrained zone therefore are potentially (depending on the cleared zonal quantity) paid a lower total price than the capacity price paid to resources in the Rest-of-Pool Capacity Zone.

For example, imagine (hypothetically) that in the FCA, 9 GW of capacity were procured in this import-constrained capacity zone. At this capacity level, the zonal demand curve specifies a price of approximately negative $3.00/kW-month. Because this value represents the congestion component of the clearing price paid in the zone, resources in Northern New England would be paid the sum of (a) the price determined by the MRI-based system-wide demand curve, and (b) the *negative* $3.00/kW-month zonal price discount specified by the MRI-based zonal demand curve. That is, at this capacity level, resources in the export constrained zone would face a negative "congestion" price, and be compensated a total price that is $3.00/kW-month less than resources in the Rest-of-Pool Capacity Zone.

Over a broad range of capacity levels (generally, above approximately 8.25 GW), the congestion price is negative for the potential export-constrained Northern New England zone. This reflects that, over this broad range of capacity levels, procuring incremental capacity in the export-constrained zone yields a lower reliability improvement than procuring incremental capacity in the Rest-of-Pool Capacity Zone.

Q: What is the zonal congestion price associated with the Maximum Capacity Limit for this zone?

A: The congestion price specified by the demand curve for the Northern New England zone at its Maximum Capacity Limit of 8,830 MW is –$1.33/kW-month. If the zone cleared at this capacity level, resources in the zone would receive a $1.33/kW-month discount relative to the price paid to resources in the Rest-of-Pool Capacity Zone. As with the zone's MRI curve, the price changes gradually as the zone's capacity level moves from just below, to just above, the Maximum Capacity Limit. This reflects that the reliability impact of incremental zonal capacity (relative to incremental capacity in the Rest-of-Pool Capacity Zone) also changes gradually in this range.

Q: How is a demand curve specifying a congestion price for an export-constrained zone used to determine the total cleared capacity in the zone?

A: As noted in Section V.C above, the process of clearing the FCA and determining clearing prices and quantities in each capacity zone is conducted simultaneously and interdependently, in accordance with the Tariff's rules governing the ISO's descending clock auction format.[13] However, the central concepts of how prices and capacity levels are determined for an export-constrained zone can be similarly illustrated simply.

As in Figure 6 in Section V.C, imagine for a moment that at the level of capacity cleared in the system overall, the MRI-based system demand curve specifies a price of $8.00/kW-month. One can conceptualize the determination of the price

[13] *See* ISO Tariff Section 13.2.3 *et seq.*

and cleared capacity in an export constrained zone by viewing the zonal demand curve as specifying the price discount (*viz.*, discounted from $8.00/kW-month) applicable to cleared capacity in the export-constrained zone. That is, think of the "total price" for the export-constrained zone as being determined by the "congestion price" demand curve discussed earlier and the clearing price in the Rest-of-Pool Capacity Zone.

Visually, Figure 9 below illustrates this conceptual "total price" demand curve logic, for the potential Northern New England capacity zone, again assuming the price in the Rest-of-Pool Capacity Zone is $8.00/kW-month. The curve in Figure 9 is based on the zone's congestion-price demand curve provided in Figure 8, except that in Figure 9 it has been "shifted up" by $8.00/kW-month at all quantities. (The curve also depicts the FCA's minimum price of $0, represented by the horizontal segment at a price of $0 above approximately 9.3 GW.)

As an example, observe that in Figure 8 previously, the congestion price at a zonal capacity level of 9 GW is (approximately) –$3.00/kW-month. The total price paid to resources in the zone, in that situation, would be the sum of –$3.00/kW-month and the price specified by the system-wide demand curve. If the latter equals the $8.00/kW-month price assumed in constructing Figure 9, then the total price paid to resources in this export-constrained zone can be read directly from Figure 9: At a zonal capacity level of 9 GW, the total price paid to resources in the export-constrained zone would be $8.00 – $3.00 = $5.00/kW-month.

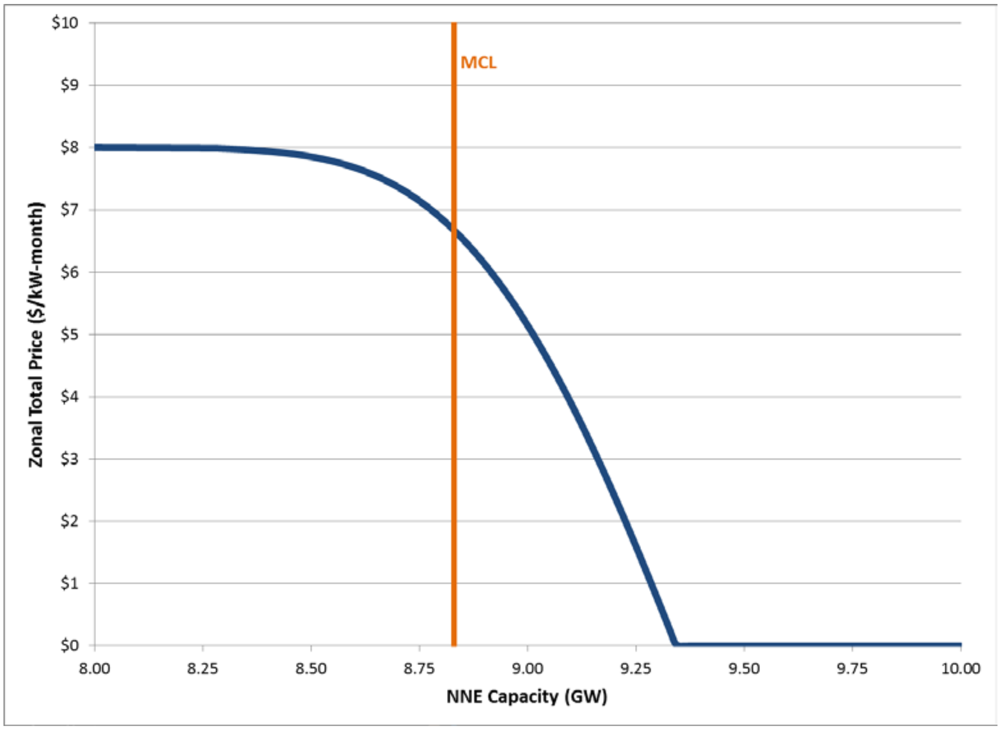

Figure 9

Q: Is this "total price" demand curve a literal description of how the ISO clears the forward capacity auction?

A: No. As noted previously in discussing the import-constrained total price demand curve example in Section V.C, this is a conceptual representation intended to convey how the price specified by the system-wide demand curve and an MRI-based zonal demand curve (which specifies congestion prices) jointly determine the clearing price in the zone. In general, clearing an additional MW in an export zone will also clear another MW in the system overall, which may change the price paid in the Rest-of-Pool Capacity Zone. The procedures used in practice to clear the FCA properly account for these interdependencies among zones and the system overall. We discuss the clearing logic that accounts for these interdependencies in Section VII.

Q: Figure 9 implies that the 'congestion' price specified by an MRI-based demand curve for an export-constrained zone cannot be less than the (negative of the) price in the Rest-of-Pool Capacity Zone. Is that correct?

A: Yes. As Figure 9 indicates, at high zonal quantities, the total price paid to resources in an export-constrained zone will reflect the price in the Rest-of-Pool Capacity Zone plus a potentially large *negative* zonal congestion price; the large negative zonal congestion price is a locational price signal that indicates to investors there is relatively little (or no) reliability improvement associated with providing incremental capacity in the export-constrained zone, relative to the Rest-of-Pool Capacity Zone.

Even in such cases, however, the clearing price for an export-constrained zone cannot fall below $0.00/kW-month. As the zone's capacity level increases, the congestion price becomes more negative because procuring incremental capacity in the export-constrained zone, relative to the Rest-of-Pool Capacity Zone, will do little to improve system reliability. As a result, the total price demand curve for the export-constrained zone slopes steadily downward in Figure 9 in this capacity range. The total price will continue to fall until it reaches $0.00/kW-month, at the capacity level for which – in this example – the export-constrained zone's congestion price is equal to –$8.00/ kW-month. In other words, the zone's congestion price cannot be less than the (negative of the) price in the Rest-of-Pool Capacity Zone.

In contrast, when the export zone has little capacity, the congestion price will tend to be close (or equal) to zero, because providing incremental capacity in the export-constrained capacity zone has a similar (or equal) reliability benefit as in the Rest-of-Pool Capacity Zone. When the congestion price is zero, resources in both the export-constrained zone and in the Rest-of-Pool Capacity Zone would be paid the same price.

Q: Will the Demand Curve Design Improvements also apply sloped zonal demand curves to external interfaces?

A: No. External interfaces will continue to be modeled as fixed limits. In theory, it may be the case that capacity on the opposite side of an external interface – that is, in an external control area – is partially substitutable for capacity inside the New England region. In practice, however, the ISO does not have planning models that are developed to simulate the marginal reliability impact of incremental capacity accurately across its interfaces with adjacent, external control areas. Accordingly, the ISO will continue to treat external interfaces as fixed limits.

E. Pricing Rule Enhancements to Accommodate Sloped Zonal Demand Curves

Q: Are modifications to the existing pricing rules necessary to accommodate sloped demand curves in import-constrained and export-constrained zones?

A: Yes. The existing pricing rules for constrained capacity zones are based on the assumption that capacity in the zones is cleared using fixed requirements (*i.e.*, vertical demand curves). With the introduction of sloped zonal demand curves that clear variable quantities, the pricing rules must be modified. These modifications are conceptually straightforward.

Q: How are the pricing rules for constrained zones modified to accommodate sloped zonal demand curves?

A: The capacity clearing price in a constrained zone will be set to the greater of two values: (1) the sum of the system clearing price paid for resources in the Rest-of-Pool Capacity Zone and the congestion price specified by the zonal demand curve at the zone's cleared quantity, or (2) the highest-priced supply bid or offer in the zone awarded a Capacity Supply Obligation.

The first of these two values sets a constrained zone's capacity clearing price in a manner consistent with the intent of the sloped zonal demand curves. The second of these two values is necessary to account for the possibility that with non-rationable supply bids and offers, the price specified by the first value could, in certain scenarios, be less than the offer or bid of the highest priced resource awarded a Capacity Supply Obligation in the zone.

Q: Please provide an example of the first case, in which the price in a zone is set by the sum of the system clearing price and the congestion price specified by the zonal demand curve at the zone's cleared quantity.

A: Figure 10 below illustrates this outcome in an import-constrained zone. In this example, the capacity clearing price paid to resources in the Rest-of-Pool Capacity Zone is represented by the symbol P_{sys}^{*}. The offers of several resources located in the import-constrained capacity shown are represented by a stepped, increasing supply curve (in purple color), and the offers of two of these resources (resource A and resource B) are indicated in the figure. (For simplicity, the supply curve in the Rest-of-Pool Capacity Zone is omitted from Figure 10).

In this example, the supply offers from resources A and resource B are both entirely to the left of the intersection of the zonal supply curve and the zone's total price demand curve (which, as discussed at the end of Section V.C, is represented by the MRI-based zonal congestion-price demand curve "shifted up" by the clearing price in the Rest-of-Pool Capacity Zone, P_{sys}^{*}). In economic terms, the offers of resource A and resource B are inframarginal in the import-constrained capacity zone.

In this situation, the offers of both resource A and resource B clear. The import-constrained zone's clearing price is set by the intersection of the zone's supply curve and the total price demand curve. This zonal clearing price (represented by the symbol P_z^*) is equal to the sum of the capacity clearing price in the Rest-of-Pool Capacity Zone (P_{sys}^*) and the price specified by the MRI-based congestion-price demand curve for the import-constrained zone at the zone's cleared quantity (represented by the symbol Q_z^*), as required.

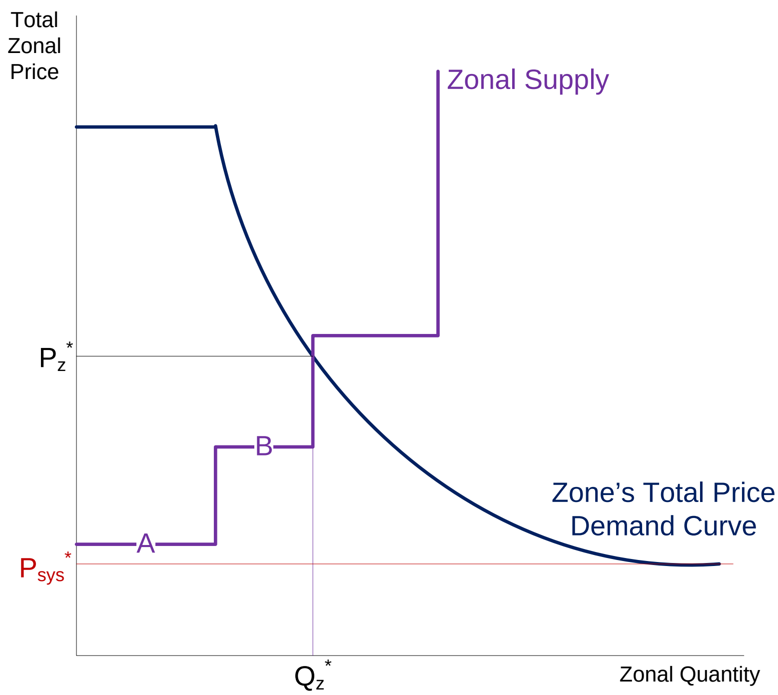

Figure 10

Q: Please provide an example of the second case, in which the price in a zone is set by the highest-priced supply bid or offer in the zone that is awarded a Capacity Supply Obligation.

A: Figure 11 below illustrates this outcome in an import-constrained zone. In this example, the capacity clearing price paid to resources in the Rest-of-Pool Capacity Zone is again represented by the symbol P_{sys}^*. The offers of several resources located in the import-constrained capacity shown are represented by a stepped, increasing supply curve (in purple color), and the offers of three of these resources – resources A, B, and C – are indicated in Figure 11. In this example, we assume all of these resources' offers are non-rationable; that is, all of the MW offered from each resource must either clear entirely, or clear not at all. (For simplicity, the supply curve in the Rest-of-Pool Capacity Zone is omitted from Figure 11).

In this example, the supply offers from resources A and B are both entirely to the left of the intersection of the zonal supply curve and the zone's total price demand curve (which, as discussed at the end of Section V.C, is represented by the MRI-based zonal congestion-price demand curve "shifted up" by the clearing price in the Rest-of-Pool Capacity Zone, P_{sys}^{*}). Resources A and B again clear and are awarded a Capacity Supply Obligation. Furthermore, clearing resource C's non-rationable supply offer increases social surplus and, as a result, resource C is also awarded a Capacity Supply Obligation.[14] The total quantity of capacity cleared in the import-constrained zone is represented in Figure 11 by the symbol Q_z^{*}.

[14] *See* ISO Tariff Section 13.3.2.7.4

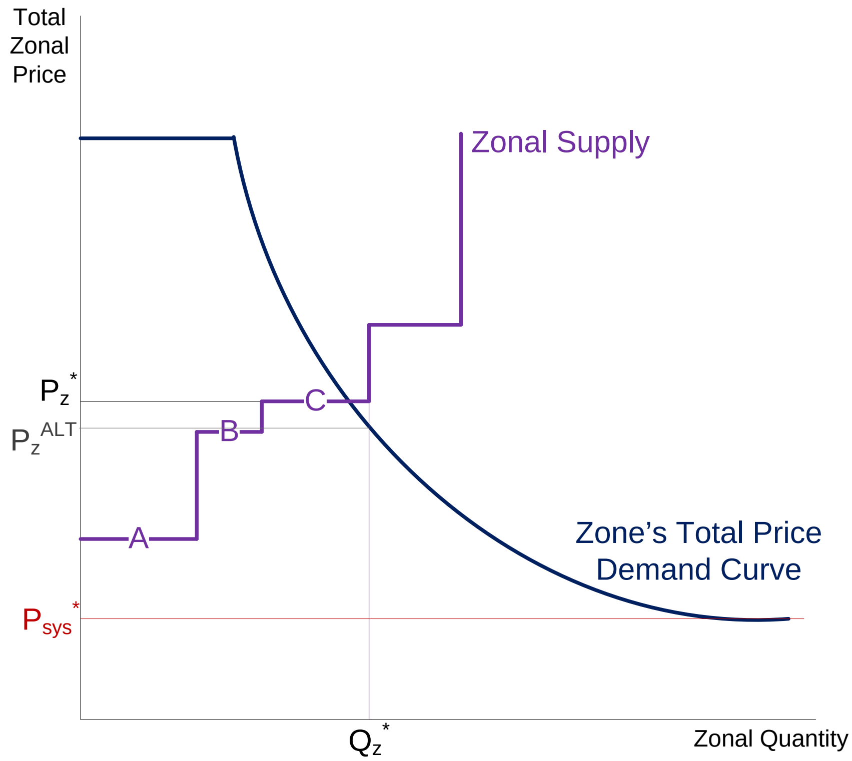

Figure 11

Observe now that among the offers comprising the zonal supply curve, a portion of resource C's offer falls to the right of the intersection of the zonal supply curve and the zone's total demand curve. If the price was set by the first case rule (*viz.*, the sum of the price paid in the Rest-of-Pool Capacity Zone and the zone's congestion price at the zone's cleared quantity), then the price provided to cleared resources in the import zone would be equal to the value shown by the symbol P_z^{ALT}. Because the offers of these cleared resources are non-rationable, this price is *less* than the offer price of the highest-priced resource awarded a Capacity Supply Obligation, resource C. To prevent paying resources awarded a Capacity Supply Obligation a price less than the offer price tendered in the auction, in this situation the capacity clearing price in the import-constrained zone would be set by the offer price of resource C, as required. In Figure 11, this capacity clearing price is represented by the symbol P_z^*.

F. <u>Annual Process for Reviewing and Updating Capacity Demand Curves</u>

Q: Under the Demand Curve Design Improvements, is the process for reviewing and updating the set of capacity demand curves with stakeholders similar to that followed in the past?

A: Yes. Currently, the system planning parameters and related information that are used to determine the sloped system demand curve and the vertical zonal demand curves are updated and reviewed with New England stakeholders during the summer and fall prior to each Forward Capacity Auction. Similarly, under the Demand Curve Design Improvements, the ISO will review these same inputs with stakeholders on the same timeframe, and present the indicative MRI-based system and zonal demand curves to stakeholders at about that time. The final system and zonal demand curves would be filed with the Commission prior to each auction, on a similar timeframe as in the past prior to the conduct of each Forward Capacity Auction.

Q: What information will be provided to describe the sloped demand curves in this process?

A: With the existing linear system demand curve and fixed zonal requirements, few parameters are needed to fully describe how demand is modeled in the Forward

Capacity Market. That is, mathematically speaking, only a few data points are needed to fully specify a linear system demand curve and the fixed zonal requirements.

With the Demand Curve Design Improvements, the number of parameters required to specify the set of MRI-based sloped demand curves grows significantly. This is because the curves are not linear, and depend on the MRI values at various capacity levels. As a result, the ISO intends to provide stakeholders with more granular demand curve data, in the form of spreadsheets with price and quantity data characterizing each demand curve, and/or mathematical formulas that serve the same end, in order to provide precise information about the MRI-based sloped demand curves for each Forward Capacity Auction. The ISO provided similar information, at a granular level, during the process of developing and reviewing these Demand Curve Design Improvements with stakeholders in 2015 and 2016.

The ISO plans to include similarly granular information in its annual Information Filing to the Commission prior to each Forward Capacity Auction, in order to provide precise information about the MRI-based sloped demand curves that will be used in the applicable Forward Capacity Auction.

VI. THE DEMAND CURVE DESIGN IMPROVEMENTS PROCURE CAPACITY COST-EFFECTIVELY, AND OTHER DEMAND CURVE DESIGNS WOULD NOT

Q: You summarized cost-effectiveness as a central design principle in prior sections of this testimony. Can you provide examples that show why the Demand Curve Design Improvements procure capacity cost effectively, and other possible demand curve designs would fail to do so?

A: Yes. In Sections IV and V, we explained the cost-effectiveness concept and its role as one of the central design principles for the Demand Curve Design Improvements. In this section, we provide several more detailed examples that clearly show how to evaluate whether a set of demand curves is cost-effective, that the current linear system curve and fixed requirements used in FCA 10 do not procure capacity cost-effectively, and that the Demand Curve Design Improvements produce curves that would procure capacity cost-effectively.

Q: How is cost-effectiveness defined, in a system with multiple capacity zones?

A: As noted in Section IV, a set of capacity demand curves is cost-effective if, for each possible clearing price in each zone, there is no way to modify the cleared capacity levels among zones that achieves the same or better system reliability at lower total bid-cost. Stated in other terms, if a set of demand curves is not cost-effective, then different demand curves would deliver the same reliability at lower total bid-cost.

Q: What is the rationale for the cost-effectiveness principle?

A: Cost-effectiveness as a principle is hard to argue with. In essence, it asks that any set of zonal demand curves pass a basic test: Can we alter the quantities demanded at the given prices, by potentially purchasing a little more in one zone and a little less in another, in a way that maintains the same overall system reliability but lowers the total bid-cost of the auction? If so, then the demand curve values at those prices could be modified, with no loss in reliability, to yield a more efficient market outcome.

Q: Is cost-effectiveness implied by the reliability and sustainability design principles?

A: No, cost-effectiveness between zones is not assured by satisfying the reliability and sustainability design principles alone. Those principles apply to the average revenue and average system reliability achieved by the design. Cost-effectiveness is a much stronger principle. It asks that at any set of clearing prices that could occur in a given auction, the demand curves should specify quantities to purchase in each zone that minimize total bid-cost for the particular level of reliability achieved in that year's auction (which, with sloped demand curves, could be higher or lower than the "1-day-in-10" Loss of Load Expectation level).

Q: Can you explain the cost-effectiveness principle with a simple numerical example?

A: Example 1 demonstrates how to check whether a set of demand levels for a system with two capacity zones is cost effective or not. It also explains why.

This example assumes a system with two zones: an import-constrained zone and the Rest-of-Pool Capacity Zone. In this hypothetical example, we assume the system clears at $8.00/kW-month, and the quantity specified at this price by a system demand curve is assumed to be 34,000 MW. We assume the import-constrained zone clears at a higher price of $10.00/kW-month, and at that price the quantity given by the import-constrained zone demand curve is 10,000 MW. These values are collected in the first two rows of data in Table 1 below; the acronym "ICZ" in the title row is shorthand for the "import-constrained zone."

Example 1	**System**	**ICZ**	**Ratio**	***Interpretation***
Total Price ($/kw-m)	$8	$10	**0.80**	*More costly in Import Zone*
Demand (MW)	34,000	10,000		
Total MRI (h/yr)	-0.67	-1	**0.67**	*More effective in Import Zone*

Table 1: Prices and quantities for Example 1

Q: How are the Total MRI values in the last row of this table interpreted?

A: This table also indicates several (hypothetical) MRI values. In this example, the MRI of additional capacity in the system is –0.67 hour/year; that means one incremental MW of capacity in the system would be used, in expectation, to reduce lost load 0.67 hours/year. We further assume capacity in the import-constrained zone is even more effective, with an MRI of –0.33 hours/year. This value represents the additional reliability benefit (*i.e.*, the greater decrease in expected energy not served) of procuring the incremental MW of capacity in the import-constrained zone, instead of in the Rest-of-Pool Capacity Zone. In Table 1, we sum these values to obtain a "Total MRI" value equal to –0.67 – 0.33 = –1.00, reported in the last row and in the column labeled ICZ.

By summing the underlying MRI values in this way, the Total MRI value of –1 shown for the import constrained zone represents the change in expected energy not served if 1 MW of incremental capacity is procured in the import constrained zone while capacity in the Rest-of-Pool Capacity Zone is held constant (so total system capacity also increases by 1 MW). That is, as shown in the last row of Table 1, the Total MRI value for system capacity of –0.67 is the reduction in expected energy not served if an incremental MW is added to the system in the Rest-of-Pool Capacity Zone, and the Total MRI value for the import-constrained zone of –1 is the is the reduction in expected energy not served if the incremental MW is added to the system in the import-constrained zone (rather than being "transferred" between the Rest-of-Pool Capacity Zone and the import-constrained zone). Using Total MRI values in this way will facilitate apples-to-apples comparisons of the reliability impact of procuring an additional MW of capacity in one zone or the other zone when a new MW is being procured, as opposed to being "transferred" between zones.

The Total MRI in an import-constrained zone is greater (in magnitude) than in the Rest-of-Pool Capacity Zone because an incremental unit of capacity in the import-constrained zone can reduce lost load that would (otherwise) occur in both: (a) the Rest-of-Pool Capacity Zone, and; (b) the import-constrained zone during conditions when the zonal interface is binding.

Q: What is the interpretation of the ratio column in Table 1?

A: The ratios represent the most important numbers in Table 1. The price ratio indicates that, at the margin, additional capacity is only 80 percent as costly in the Rest-of-Pool Capacity Zone as in the import-constrained zone. The Total MRI ratio illustrates that additional capacity is 67 percent as effective in improving reliability (reducing expected lost load) in Rest-of-Pool Capacity Zone as in the import-constrained zone. For this reason, we will refer to the Total MRI ratio as the "reliability ratio."

Q: Do the demand curves in this example procure capacity cost-effectively?

A: No. Because the price and reliability ratios in Table 1 are not equal, the demand curves used in Example 1 are not cost effective. At these prices, they demand too much capacity in the Rest-of-Pool Capacity Zone relative to the import-constrained zone. Reducing demand in the Rest-of-Pool Capacity Zone and increasing it in the import-constrained zone – at the right rates – can deliver the same reliability at lower cost.

Q: Can you explain how a change in demand can produce the same reliability at lower cost?

A: Yes. Consider what happens if we procure 1 MW less in the Rest-of-Pool Capacity Zone, and 0.67 MW more in the import-constrained zone. This leads to a net decrease of 0.33 MW of total system capacity. However, because capacity in the Rest-of-Pool Capacity Zone only provides two-thirds of the reliability value of that in the import-constrained zone, total reliability (expected energy not served) is unchanged. This scenario is shown in Table 2 below.

Example 1	**ROP**	**ICZ**	**Total**	***Interpretation***
Δ Capacity (MW)	-1	+ 0.67	**- 0.33**	*Less total capacity*
Δ EENS (MWh)	+ 0.67	- 0.67	**0**	*Same reliability*
Δ Cost ($/mo)	- $8,000	+ $6,667	**- $1,333**	*Lower total cost*

Table 2: A more cost-effective procurement for Example 1

In Table 2, the “triangle” symbols at the start of each row are notation to indicate the change in each value when we procure 1 MW less in the Rest-of-Pool Capacity Zone, and 0.67 MW more in the import-constrained zone. The total expected energy not served (denoted “EENS” in Table 2) is unchanged by procuring 1 MW less capacity in the Rest-of-Pool Capacity Zone and 0.67 MW more capacity in the import-constrained zone. However, total cost is lower. As the bottom row of Table 2 indicates, the cost of capacity in the Rest-of-Pool Capacity Zone decreases by $8,000/month, because 1 MW less is procured there. In the import-constrained zone, the cost associated with purchasing an additional 0.67 MW of capacity increase by $6,667/month. Combining these values yields a decrease in total system costs by $1,333/month, relative to the quantities procured in Table 1.

This calculation shows that the demand curves used to set the clearing prices and quantities in Table 1 are not cost effective. Modifications to the quantities specified by the demand curve at these prices, as indicated in Table 2, yield the same expected reliability at lower total cost.

Q: How does this apply to the FCM under the current rules? Can you provide a numerical example supporting the concern that the existing linear system demand curve and fixed zonal requirements may fail to produce cost-effective outcomes?

A: Yes. Here, we provide a second example that uses data corresponding to the FCA 10 zonal configuration and system planning parameters. For consistency with Example 1, here we will assume that the clearing prices are again $8.00/kW-month in the Rest-of-Pool Capacity Zone and $10.00/kW-month in the import-constrained zone. (In FCA 10, the actual clearing prices did not exhibit price separation).

In FCA 10, at a price of $8.00/kW-month the linear system demand curve specified a MW quantity of 35,213 MW. Analysis of system reliability with FCA 10 system planning parameters produces an MRI value for this system capacity level of –0.259 hours/year. In FCA 10, there was an import-constrained zone modeled in the auction: the Southeast New England Capacity Zone, which had a Local Sourcing Requirement of 10,028 MW. As a result of modeling the Local

Sourcing Requirement as a fixed requirement, the market will clear 10,028 MW in the zone when the zonal prices separate, but there is sufficient capacity in the import-constrained zone to meet the requirement. Accordingly, we assume here that at a price of $10.00/kW-month, the Southeast New England Capacity Zone will clear 10,028 MW of capacity. At this capacity level, the same reliability analysis indicates that Total MRI for that import-constrained zone is –0.302 hours/year. These values are collected in the table below:

Example 2	**System**	**ICZ**	**Ratio**	***Interpretation***
Total Price ($/kw-m)	$8	$10	**0.80**	*More costly in Import Zone*
Demand (MW)	35,213	10,028		
Total MRI (h/yr)	-0.259	-0.302	**0.86**	*More effective in Import Zone*

Table 3: Prices and quantities for Example 2

Q: Are these prices and MRI values consistent with cost-effective outcomes?

A: No. As Table 3 indicates, the price and reliability ratios are not equal. Instead, capacity in the Rest-of-Pool Capacity Zone is only 80 percent as expensive as that in Southeast New England, but it provides 86 percent as much reliability improvement (in terms of expected energy not served).

Table 4 below summarizes a change in capacity procured in each zone (since this differs from the current market rules, we call this scenario a "counterfactual"). In this counterfactual scenario, imagine the demand curves are modified to procure 1 MW more in the Rest-of-Pool Capacity Zone and 0.86 MW less in the Southeast New England Capacity Zone. These capacity changes are examined because they are in a ratio equal to the Total MRI ratio between zones, as shown in the last row of Table 3. While these modifications to the capacity procured in each zone increase the total cleared capacity by 0.14 MW, there is no change in reliability (as measured by expected energy not served). However, total costs decrease by $600/month in this counterfactual scenario, relative to the initial cleared quantities presented in Table 3 that would be procured, in this scenario, under the ISO's current linear system demand curve and vertical zonal curve. As a result, the existing system linear curve and fixed zonal requirements do not procure capacity in a cost-effective manner.

Example 2	**ROP**	**ICZ**	**Total**	***Interpretation***
Δ Capacity (MW)	+1	- 0.86	**- 0.14**	*Less total capacity*
Δ EENS (MWh)	- 0.259	+ 0.259	**0**	*Same reliability*
Δ Cost ($/mo)	+ $8,000	- $8,600	**- $600**	*Lower total cost*

Table 4: The counterfactual scenario is more cost effective

Q: At the prices in these examples, do the new MRI-based demand curves procure capacity cost-effectively? How do we see this?

A: Yes. We can show this by using the quantities specified by the MRI-based demand curves. Example 3 below uses the FCA 10 zonal configuration and system planning parameters as before, but now applies the MRI-based sloped demand curves for both the Rest-of-Pool Capacity Zone and the Southeast New England Capacity Zone. For the sake of continuity and clarity of these examples, we assume again the same clearing prices in each zone. (In practice, a change in the quantities procured in the FCA will generally impact the clearing prices;

assuming the same prices as before will make Example 3 below simpler to follow, and does not alter the general conclusion illustrated here).

At a clearing price of \$8.00/kW-month, the indicative MRI-based system demand curve specifies a quantity of 34,549 MW. The MRI value corresponding to this system quantity is –0.442 hours/year. In the Southeast New England Capacity Zone, a total clearing price of \$10.00/kW-month corresponds to a \$2.00/kW-month 'congestion' price premium. This price corresponds to a cleared quantity of 9,786 MW for the Southeast New England Capacity Zone and yields a Total MRI value for the zone –0.553 hours/year. As shown in Table 5, the price and reliability ratios are therefore equal. Incremental capacity is 80 percent as expensive in the Rest-of-Pool Capacity Zone as in the Southeast New England Capacity Zone, and incremental capacity delivers 80 percent as much reliability improvement (in terms of expected energy not served).

Example 3	**System**	**ICZ**	**Ratio**	***Interpretation***
Total Price (\$/kw-m)	\$8	\$10	**0.80**	*More costly in Import Zone*
Demand (MW)	34,549	9,786		
Total MRI (h/yr)	-0.442	-0.553	**0.80**	*More effective in Import Zone*

Table 5: Prices and quantities for Example 3

Q: Does the equality of the price and reliability ratios indicate that the MRI-based sloped demand curves are cost effective at these cleared capacity levels?

A: Yes. Because the price and reliability ratios are equal, it is not possible to procure more capacity in one zone, and less capacity in the other, and achieve the same level of system reliability at lower cost. As a result, the MRI-based demand curves used for Example 3 are cost effective.

This result holds true in general, although in this example we have illustrated this property at the specific prices and quantities listed in Table 5. The generality of this result does not require exhaustively checking tables of results for every possible price level; rather, it can be verified using general mathematical formulas. The general result is explained in detail on pages 23-25 of the ISO's Technical Memorandum.

Q: What is the economic interpretation of procuring capacity at levels for which the price ratio and the reliability ratio are equal across zones?

A: By procuring capacity using demand curves that satisfy this property, the Demand Curve Design Improvements ensure that the price paid to avoid expected lost load (on a per MWh basis) is the same in each zone. This characteristic is fundamental to the cost-effectiveness design principle because if the market does not pay the same price to avoid expected lost load (on a per MWh basis) in every zone, then it is possible to achieve the same reliability at lower cost – as illustrated in Examples 1 and 2 above.

Q: Does the cost-effectiveness design principle also result in price ratios and reliability ratios that are equal in the presence of more than two capacity zones?

A: Yes. Examples 1 through 3 consider a system with one import-constrained zone. In this scenario, there is only one price ratio and one reliability ratio to evaluate. With the introduction of a second constrained zone, there are now multiple price and reliability ratios that can be evaluated: the Rest-of-Pool Capacity Zone to constrained zone A, the Rest-of-Pool Capacity Zone to constrained zone B, and so forth. The cost-effective MRI-based demand curve design ensures that the price ratios and reliability ratios will be the same for each of these pairs. (The price ratios and reliability ratios will also be the same between constrained zone A and constrained zone B, and so on).

Q: How are the price and reliability ratios applied when the system has an export-constrained capacity zone?

A: Under the Demand Curve Design Improvements, an export-constrained zone's sloped demand curve is derived to ensure that the export-constrained zone and the Rest-of-Pool Capacity Zone's price and reliability ratios will be equal. The key difference is that capacity in the export-constrained zone will have less of a beneficial reliability impact than that in the Rest-of-Pool Capacity Zone. To ensure that the price and reliability ratios are equal, the price paid to resources in the export-constrained zone must therefore be proportionally less than that the price paid to resources in the Rest-of-Pool Capacity Zone. For example, if the price in the Rest-of-Pool Capacity Zone is $8.00/kW-month and the price in an export zone is $6.00/kW-month, then the MRI value of capacity in the export zone must also be 75% percent (*i.e.,* $6.00 / $ 8.00 = 0.75) of that in the Rest-of-Pool Capacity Zone.

Q: Will any set of curves where the price and reliability ratios are not equal for all cleared capacity levels fail to be cost effective?

A: Yes, that is correct. If there is any set of capacity levels for which the price and reliability ratios produced by the demand curves is not equal, then those demand curves do not satisfy the cost-effective procurement design principle. In such cases, for some (perhaps all) price levels, it would be possible to buy less capacity in one zone and more in another and achieve the same reliability at lower bid-cost.

Q: Does the cost-effectiveness principle hold for a design that uses MRI-based zonal demand curves and retains the existing linear system curve?

A: No. For the cost-effectiveness principle to hold, the price and reliability ratios must be equal for all capacity levels and across all capacity zones. This includes the ratio of prices and MRI values between the Rest-of-Pool Capacity Zone and a constrained zone. As a result, the MRI-based methodology used to derive the cost-effective set of demand curves must be applied not just to the constrained zones, but also to the system-wide demand curve. Otherwise, if the constrained zone sets the capacity price based on its MRI value and the Rest-of-Pool Capacity

Zone instead sets the price based on a linear curve that is not based on capacity's MRI value, the price and reliability ratios will not be equal (for some or all capacity levels). As a result, the same system reliability could be achieved at lower cost by using an MRI-based system demand curve. That is, to ensure that the price ratio is equal to the reliability ratio, the prices must be set in proportion to capacity's MRI value in both constrained capacity zones and at the system level.

Q: Please provide a numerical example showing that a design which uses the existing linear system curve and the MRI-based zonal curves is not cost effective.

A: Certainly. In Example 4 below, we again use the FCA 10 zonal configuration and system planning parameters. It applies the existing linear system curve used in FCA 10 and the MRI-based sloped demand curves for Southeast New England. As with the previous examples, the clearing price for the Rest-of-Pool Capacity Zone is assumed to be \$8.00/kW-month and the clearing price in the Southeast New England Capacity Zone is assumed to be \$10.00/kW-month. Because this case uses the same linear system demand curve as applied in Example 2 and clears at the same price, the cleared quantity and MRI value for the system is the same as in Example 2. The cleared quantity for the import-constrained zone is the same in this scenario as in Example 3 previously, and the Total MRI value for the import-constrained zone in this scenario is shown in Table 6 below:

Example 4	System	ICZ	Ratio	*Interpretation*
Total Price ($/kw-m)	$8	$10	**0.80**	*More costly in Import Zone*
Demand (MW)	35,213	9,786		
Total MRI (h/yr)	-0.259	-0.370	**0.70**	*More effective in Import Zone*

Table 6: Prices and quantities for Example 4

Q: Are these prices and MRI values consistent with cost-effective outcomes?

A: No. As Table 6 indicates, the price and reliability ratios are not equal. Instead, capacity in the Rest-of-Pool Capacity Zone is 80 percent as expensive as that in the Southeast New England Capacity Zone, but only provides 70 percent as much reliability improvement (in terms of reducing expected energy not served). As a result, if the cleared capacity in the Rest-of-Pool Capacity Zone decreases by 1 MW and the cleared capacity in the Southeast New England Capacity Zone increases by 0.70 MW, the total expected energy not served would be unchanged.

Table 7 below provides a new counterfactual scenario, which procures a little more capacity in the import-constrained zone and a little less in the Rest-of-Pool Capacity Zone. As seen in the table, total cleared capacity decreases by 0.30 MW, with no change in expected energy not served. However, total costs decrease by $1,000/month. This reveals that a design that uses the existing system linear curve and a MRI-based zonal demand curve will still fail to procure capacity consistent with the cost-effective design principle.

Example 4	ROP	ICZ	Total	*Interpretation*
Δ Capacity (MW)	-1	+ 0.7	**- 0.3**	*Less total capacity*
Δ EENS (MWh)	+ 0.259	- 0.259	**0**	*Same reliability*
Δ Cost ($/mo)	- $8,000	+ $7,000	**- $1,000**	*Lower total cost*

Table 7: Counterfactual scenario for Example 4

VII. THE DEMAND CURVE DESIGN IMPROVEMENTS ENABLE CAPACITY SUBSTITUTION ACROSS ZONES DURING THE AUCTION, WHICH IMPROVES AUCTION COMPETITIVENESS AND RELIABILITY OUTCOMES

A. The Quantity Demanded in a Zone Depends on the Quantities Cleared in Other Zones

Q: How do the sloped demand curves determine which suppliers are awarded Capacity Supply Obligations?

A: Generally, supply resources that are awarded a Capacity Supply Obligation have bid/offer prices that are below the Capacity Clearing Price for the zone in which they are located, and resources that are not awarded Capacity Supply Obligations have bid/offer prices that are above the Capacity Clearing Price for the zone in which they are located. The clearing process of the Forward Capacity Auction is designed to be consistent with the economic principle of social surplus maximization, which promotes market efficiency.

Q: Are clearing outcomes in a constrained capacity zone dependent on the conditions outside of the zone?

A: Yes. The introduction of sloped zonal curves that reflect congestion prices means that, to be consistent with this overall market efficiency objective, the quantity of capacity awarded a Capacity Supply Obligation in any zone will depend on the quantities cleared in the other zones. Further, the clearing price paid to capacity suppliers in a constrained capacity zone is not only dependent on the cleared quantity in that zone, but on the clearing price paid to resources in the Rest-of-Pool Capacity Zone.

Q: Are clearing outcomes in the Rest-of-Pool Capacity Zone also dependent on conditions in constrained zones?

A: Yes. The demand curve used to determine the clearing price and quantity for the Rest-of-Pool Capacity Zone considers all system capacity including that in constrained zones. As a result, the cleared capacity in each constrained zone will impact the price and quantity of capacity cleared in the Rest-of-Pool Capacity Zone. Because the clearing price and quantity in each zone depend on conditions in other zones, clearing is interdependent between zones.

Q: Can you more precisely explain what is meant by interdependent clearing?

A: Interdependent clearing means that the clearing prices and quantities in each capacity zone cannot be determined independently. Instead, the price and quantity are dependent on supply and demand in all zones. As a result, if the supply conditions change in the Rest-of-Pool Capacity Zone, it will impact clearing outcomes not only in this zone, but in each constrained zone as well. Similarly, if the supply conditions change in a constrained zone, it will impact clearing outcomes in the Rest-of-Pool Capacity Zone and all other constrained zones.

Q: Please provide a graphical example illustrating interdependent clearing, in the context of the MRI-based system and zonal demand curves.

A: This interdependence is illustrated in Figure 12 below, applicable to a system with two capacity zones. The left panel represents the system demand curve and also shows the supply curve for resources in the Rest-of-Pool Capacity Zone. The right panel represents supply and demand in the import-constrained capacity zone.

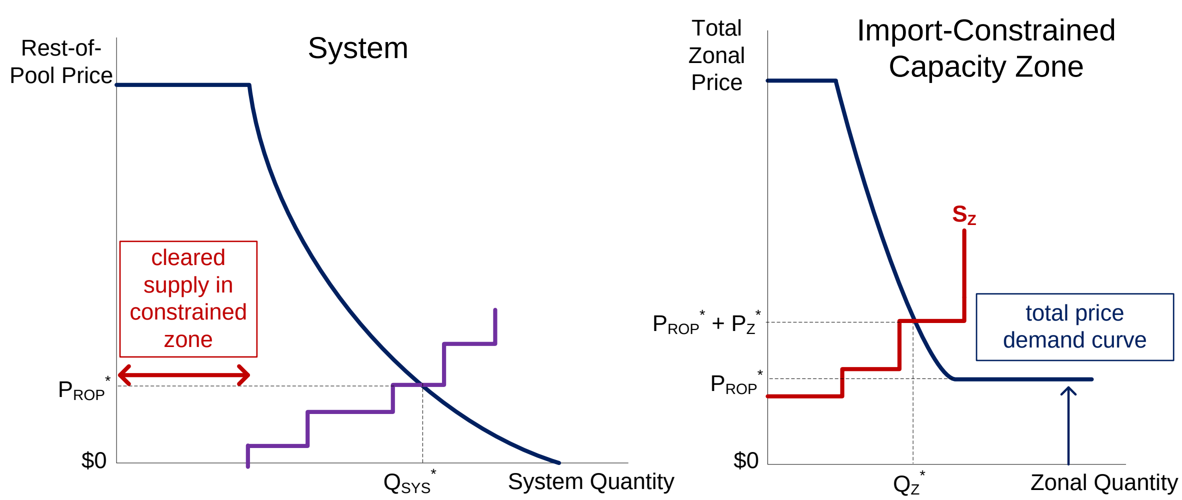

Figure 12

In the left panel, the total cleared system quantity of capacity (denoted by the symbol Q_{SYS}^*) and the clearing price paid to resources in the Rest-of-Pool Capacity Zone (denoted by P_{ROP}^*) depend explicitly on the amount of supply cleared in the constrained zone. If additional lower-cost capacity is offered in the constrained zone and clears, it will tend to displace higher-cost supply offers (that would otherwise be cleared) in the Rest-of-Pool Capacity Zone. Visually, clearing additional lower-cost capacity in the constrained zone would "shift" the supply curve to the right in the Rest-of-Pool Capacity Zone shown in the left panel of Figure 12; due to the downward sloping system demand curve, that will tend to increase the total cleared capacity in the system overall. This increase in total cleared system capacity would decrease the price paid to resources in Rest-of-Pool Capacity Zone.

Q: And how is the price and quantity cleared in the constrained zone determined?

A: The right panel in Figure 12 depicts the supply curve of resources in the import-constrained zone, and the "total price" demand curve for the import-constrained capacity zone. The total price demand curve for an import-constrained zone was discussed in Section V.C (see Figure 6), and is equal to the sum of the clearing price paid in the Rest-of-Pool Capacity Zone (P_{ROP}^*) and the import-constrained zone's MRI-based congestion price demand curve.

The clearing price paid to resources in the import-constrained capacity zone is represented by the intersection of the zone's supply curve (shown in red color) and the zone's total demand curve (shown in dark blue color) on the right panel of Figure 12. In that panel, the capacity clearing price for the import-constrained zone is represented by the symbols ($P_{ROP}^* + P_Z^*$); the symbol P_Z^* represents the zonal congestion price specified by the MRI-based zonal congestion price demand curve at the zone's cleared quantity (Q_Z^*).

As a result, the clearing price and quantity in the import-constrained zone is clearly dependent on the clearing price in the Rest-of-Pool Capacity Zone. For example, if additional lower-cost capacity is offered in the Rest-of-Pool Capacity Zone and clears, that will tend to decrease the price in the Rest-of-Pool Capacity Zone; in turn, the lower price in the Rest-of-Pool Capacity Zone would be represented by a "downward shift" in the total price demand curve for the import constrained zone, which would reduce both the clearing price and quantity in the import constrained zone.

Q: In practice, is the FCA cleared by sequentially adjusting these supply and demand curves for each zone to find the clearing prices and quantities?

A: No, that is not necessary. Figure 12 is an illustration that explains the economic logic of why the clearing prices and quantities are interdependent across zones. In practice, the ISO uses sophisticated software during (and after) the Descending Clock Auction to determine the cleared prices and quantities in each capacity zone. This software simultaneously determines the quantities in each zone and the clearing prices, which correspond to the outcomes illustrated in Figure 12 in that scenario.

B. <u>Interdependent Clearing Enables Capacity Substitution Across Zones During the Auction, Improving the Auction's Competitiveness</u>

Q: How does the interdependence in clearing enable capacity substitution between zones?

A: This interdependent clearing allows the market to clear capacity where its marginal reliability impact is greatest relative to capacity's cost. More specifically, as supply conditions are revealed during the course of the Descending Clock Auction, interdependent clearing will allow the market to substitute toward clearing more resources in zones where capacity is relatively less expensive, and away from resources in zones where it is relatively more expensive.

Q: Please explain further.

This can best be illustrated with an example that extends the earlier Figure 12. This extended example assumes the same set of supply and demand curves. However, we now introduce an additional, low-cost capacity resource in the Rest-of-Pool Capacity Zone, which we will call resource A. Because of interdependent clearing, this Resource will not only affect the price and quantity cleared in the Rest-of-Pool Capacity Zone, but also the clearing price and quantity in the import-constrained capacity zone.

More specifically, the impact of resource A is illustrated in Figure 13 below. The price and quantity symbols that are indexed with an asterisk ("*") (and shown in gray) represent the initial values shown previously in Figure 12, prior to the introduction of resource A. The price and quantity symbols that are indexed with an "A" represent the updated outcomes that reflect the introduction of low-cost resource A in the Rest-of-Pool Capacity Zone.

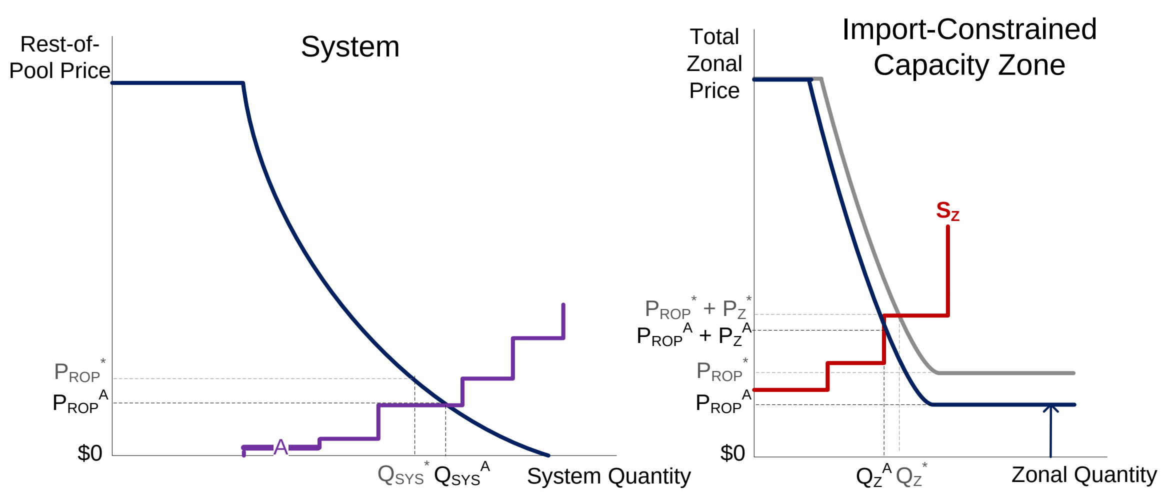

Figure 13

As shown in the left panel of Figure 13, the introduction of inexpensive supply from resource A in the Rest-of-Pool Capacity Zone increases the total cleared system capacity. (Total system capacity cleared increases from Q_{SYS}^* to Q_{SYS}^A). This increased total cleared system capacity also reduces the clearing price paid to resources in the Rest-of-Pool Capacity Zone according to the system demand curve. (The Rest-of-Pool Capacity Zone clearing price decreases from P_{ROP}^* to P_{ROP}^A in Figure 13). Each of these price and quantity changes in the Rest-of-Pool

Capacity Zone is intuitive, as any increase in supply tends to increase total cleared quantity and decrease price in a market with a sloped demand curve.

Interdependent clearing implies that clearing resource A in the Rest-of-Pool Capacity Zone will also impact clearing prices and quantities in the import-constrained capacity zone. This is shown in the right panel of Figure 13. There, the import-constrained zone's supply curve is unchanged from before, but the total price demand curve for the zone is changed. Specifically, the total price demand curve for the zone is lower ("shifted down"), due to the lower clearing price in the Rest-of-Pool Capacity Zone. The total capacity cleared in the import-constrained zone decreases (from Q_Z^* to Q_Z^A) as a result of this downward shift in the total price demand curve. With the lower cleared quantity in the import-constrained zone, the clearing price in the import-constrained zone also decreases (in Figure 13, this is the price decrease from the level denoted by ($P_{ROP}^* + P_Z^*$) to the price level denoted by ($P_{ROP}^A + P_Z^A$)).

In sum, when a supply resource is offered at a low price, the clearing process will tend to substitute this low-priced capacity for other, higher-priced resources that may be located in another zone – even an import-constrained zone. We call this effect *capacity substitution* across zones. The substitution is not, in general, at a 1 MW-for-1 MW rate across zones, as the effect depends upon the slopes of the demand curves in each zone (and, more fundamentally, on the MRI of capacity in each zone). Nonetheless, this capacity substitution effect is important to competitive capacity auctions because it shows that even when there is price separation between zones (as illustrated in Figures 12 and 13), under the Demand Curve Design Improvements the marginal resource in a constrained zone is competing not only with the other supply resources within the same zone, but also competing directly with supply offered throughout the whole system.

Q: Is this capacity substitution effect consistent with the cost-effectiveness design principle?

A: Yes. At a high level, the introduction of additional low-cost supply in the Rest-of-Pool Capacity Zone leads the system to clear more capacity in that zone and less in the import-constrained capacity zone. This outcome is consistent with the cost-effectiveness design principle because the market is realigning the amounts procured in each zone according to the properties explained in Section VI of this testimony: It is ensuring that the price ratio between zones remains equal to the reliability ratio between zones, when new lower-cost supply is available in one of the two zones. The slopes of MRI-based demand curves are expressly constructed (by virtue of using the same scaling factor) to substitute just enough capacity across zones to ensure that the price ratio equals the reliability ratio.

Q: And, under the Demand Curve Design Improvements, this holds generally?

A: Yes. While Figure 13 provides an example where low-cost capacity is added to the Rest-of-Pool Capacity Zone, the Demand Curve Design Improvements will substitute away from where capacity becomes relatively more costly to where it becomes relatively less costly across a wide range of scenarios. For example, if the additional inexpensive capacity was instead added in the import-constrained capacity zone, the market would again substitute in a cost-effective manner by clearing more capacity in the import-constrained capacity zone where it has become relatively less expensive, and less capacity in the Rest-of-Pool Capacity Zone where it has become relatively more expensive. Similar examples can be constructed where the change in supply occurs because a resource exits the market, or the system has an export-constrained capacity zone.

Q: Please summarize how this capacity substitution effect enhances the competitiveness of the capacity auctions.

A: By allowing for the substitution of capacity across zones, capacity suppliers compete in the Forward Capacity Auction not only with other suppliers in the same capacity zone, but with all capacity suppliers in New England. This broad-based competition also occurs under current rules in limited conditions – namely, when there is no price separation between capacity zones. In contrast, under the Demand Curve Design Improvements, even when there is price separation between zones the marginal resource in each zone is competing, to some degree, with the marginal resource in all other zones. The intensity of this competition depends on whether the zonal demand curves are relatively steep, or relatively flat, at the zonal capacity level where the zone's marginal resource would clear. This is appropriate, inasmuch as the slope of the zone's demand curve directly reflects – by construction – the reliability impact of clearing the marginal resource in that capacity zone, instead of clearing another increment of capacity in the Rest-of-Pool Capacity Zone.

Q: By ensuring that each supplier competes to some degree with all resources in the system, do the Demand Curve Design Improvements help to protect against market power?

A: Yes. By increasing the number of competitors each capacity supplier effectively competes with in the auction, the Demand Curve Design Improvements will help protect against the exercise of market power. More specifically, if a capacity supplier aims to withhold a portion of its capacity to increase the clearing price in its zone, the price impact corresponding to this action will be attenuated because the capacity auction will tend to clear additional, lower-cost capacity in another zone as a result. This will lessen (perhaps greatly) the financial incentive for a large resource owner in a constrained zone to withhold a portion of its capacity in the first place.

This property is consistent with the observations of both the Internal Market Monitor and the External Market Monitor, who each noted that the interdependent clearing employed under the Demand Curve Design Improvements may help to alleviate market power concerns in the Forward Capacity Market (see Attachments 3 and 4 to this filing, respectively).

C. Interdependent Clearing During the Auction Can Improve Reliability Outcomes and Reduce Price Volatility

Q: How does interdependent clearing impact reliability outcomes?

A: The current rules only allow capacity to be substitutable when there is no price separation between zones. This requires an import-constrained zone to be long of its Local Sourcing Requirement, or and export-constrained zone to be short of its Maximum Capacity Limit. In those situations, the current Forward Capacity Auctions clear as if incremental capacity in a constrained zone and in the Rest-of-Pool Capacity Zone as equivalent from a reliability perspective.

As explained in Section V above, this is not the case. The MRI curve for Southeast New England shown in Figure 4 in Section V.C. indicates that even at (and above) that zone's Local Sourcing Requirement, the reliability impact of incremental capacity in that zone is greater (in magnitude) than the reliability impact of incremental capacity in the Rest-of-Pool Capacity Zone.

The Demand Curve Design Improvements recognize that a variety of combinations of capacity levels in the capacity zones can meet the system's resource adequacy objective, including combinations where there is less capacity in an import-constrained zone than its Local Sourcing Requirement under current rules. This enables the FCM to substitute capacity between zones in response to price, reducing price volatility while improving reliability outcomes.

Q: Is it possible to meet the resource adequacy objective even if an import-constrained zone's MRI-based demand curve procures less than the zone's Local Sourcing Requirement under existing rule?

A: Yes. Because capacity is substitutable across zones for a broad range of capacity quantities, it may be possible to meet the system's "1-day-in-10" Loss of Load Expectation ("LOLE") planning standard even in cases where an import-constrained zone procures less capacity than its Local Sourcing Requirement. In fact, under system conditions where capacity in the import-constrained capacity zone is relatively expensive and capacity in the Rest-of-Pool Capacity Zone is relatively inexpensive, the additional capacity procured in the Rest-of-Pool Capacity Zone under the MRI-based system demand curve can fully offset the reliability impact (in terms of expected loss of load) from procuring less than the Local Sourcing Requirement in the import-constrained capacity zone.

Q: Please provide a numerical example illustrating that even when an import-constrained capacity zone clears less than its Local Sourcing Requirement, the MRI-based demand curves satisfy the "1-day-in-10" LOLE criterion.

A: As in FCA 10, consider a two-zone system with an import-constrained capacity zone in Southeast New England. Imagine that the system cleared 35,151 MW of capacity in total, which is 1,000 MW in excess of the FCA 10 Net ICR value. Furthermore, imagine that Southeast New England Capacity Zone clears only 9,728 MW of capacity, which is 300 MW less than its Local Sourcing Requirement (using FCA 10 values).

As explained in detail on pages 7-8 of the ISO's Technical Memorandum, the expected energy not served for the system can be calculated as the sum of two components: (1) the expected energy not served determined without considering the interface constraints between capacity zones, given the system's total capacity, and (2) the *additional* expected energy not served that is caused by these interface constraints between zones, given the share of total capacity cleared within each capacity zone. While this two-component formula to calculate total system reliability has been discussed in the context of the expected energy not served reliability metric, it is equally applicable to the system LOLE reliability metric.

To evaluate the total LOLE that results from the cleared quantities in this example, we have calculated the two components of LOLE described above using the system planning parameters applicable in FCA 10. These are as follows: (1) A LOLE of 0.053 determined without considering the interface constraints between capacity zones, given a system total capacity of 35,151 MW; and (2) an additional LOLE of 0.035 that is caused by the interface constraint between zones, given the share of total capacity cleared in the Southeast New England Capacity Zone is 9,728 MW.[15] Summing these values to values yields a total LOLE of 0.053 + 0.035 = 0.088. The "1-day-in-10" LOLE planning standard

[15] The additional 0.037 LOLE value is calculated using the capacity transfer capability between the Rest-of-Pool Capacity Zone and the Southeast New England Capacity Zone described in the McBride Testimony and applicable to the calculation of the MRI-based demand curves under the Demand Curve Design Improvements.

requires a total LOLE value of 0.1 or less, which is satisfied by the LOLE value of 0.088 in this example.

Q: Does interdependent clearing between capacity zones reduce the volatility in prices and reliability outcomes from one year to the next?

A: Yes. Interdependent clearing will tend to alleviate volatility in both capacity clearing prices and reliability outcomes from one year to the next. To see why, imagine a system with an import-constrained capacity zone and a Rest-of-Pool Capacity Zone, and consider the impact of a large resource retirement in the Rest-of-Pool Capacity Zone on prices and reliability outcomes (in terms of expected energy not served).

The resource retirement may result in significantly less capacity being cleared in the Rest-of-Pool Capacity Zone, but if clearing is not interdependent across zones, the retirement may not alter the cleared quantity in the import-constrained capacity zone. This would be the case under the current rules with a vertical zonal demand curve if there is price separation from the Rest-of-Pool Capacity Cone with the resource retirement. In this case, the resource retirement may lead to higher prices in the Rest-of-Pool Capacity Zone and lower system reliability (in terms of expected energy not served), if additional supply is not available to replace the retirement at the same or lower price.

The Demand Curve Design Improvements use interdependent clearing, which helps to mitigate the impact of the retirement. More specifically, even if additional supply is not available to replace the retirement at the same or lower price, the reduction in cleared capacity in the Rest-of-Pool Capacity Zone will be partially offset by clearing additional capacity in the import-constrained capacity zone. This is the capacity substitution effect. This additional capacity will reduce the retirement's adverse impact on system reliability.

Furthermore, as illustrated in Figure 12 in Section VII.A above, this additional capacity cleared in the import-constrained capacity zone is counted toward the total system capacity when determining the clearing price on the system demand curve that is paid to resources in the Rest-of-Pool Capacity Zone. The additional capacity in the import-constrained capacity zone effectively moves the supply curve for resources in the Rest-of-Pool Capacity zone further to the right (*c.f.* Figure 12, left panel); that decreases the Rest-of-Pool Capacity Zone clearing price, and partially offsets the price impact of the retirement in the Rest-of-Pool Capacity Zone.

In sum, by substituting capacity purchases between zones in response to this (hypothetical) retirement, the interdependent clearing under the Demand Curve Design Improvements will tend to help alleviate volatility in prices and reliability outcomes when the system experiences large retirements. While the above example illustrates how this occurs when a retirement occurs in the Rest-of-Pool

Capacity Zone, the effects are similar when a retirement (or new entry) occurs in a constrained zone.

VIII. THE DEMAND CURVE DESIGN IMPROVEMENTS PERFORM WELL UNDER A WIDE RANGE OF POSSIBLE FUTURE SUPPLY CONDITIONS

Q: Why is it important to test the performance of the sloped demand curves across a range of potential future supply conditions?

A: Because future supply conditions are uncertain, it is important to evaluate the performance of the sloped demand curves under several potential future supply conditions. To do so, we must evaluate outcomes when the demand curves are determined using the Demand Curve Design Improvements for a number of possible supply curves. Such analysis will allow for the evaluation of the demand curves across a range of market conditions that could occur in future auctions.

Q: How did the ISO gauge the reliability performance of the sloped demand curves?

A: Consistent with the reliability design principle, for a variety of supply scenarios we assessed the reliability outcomes produced by the sloped zonal demand curves. In particular, to perform well, the sloped demand curves need to deliver reliability in the range of 0.1 LOLE across a broad range of supply conditions.

Q: Were other performance factors such as the volatility of clearing prices examined?

A: These factors were examined in certain assessments, but there are not objective, quantitative performance targets for metrics such as price volatility. Volatility metrics were not specified among the central design principles of these Demand Curve Design Improvements because it is difficult to develop an objective criterion for how much volatility is economically appropriate in a market.

Moreover, market price volatility that is directly attributable to fluctuations in sound market fundamentals is entirely appropriate, as it serves to send time-varying investment price signals that induce resources to enter (when needed) or exit (when no longer needed or economic to operate). Because the MRI-based sloped demand curves are based on the incremental reliability impact of capacity, we expect that volatility in prices from year-to-year will be consistent with the incremental reliability impact of capacity, and thereby send appropriate locational price signals in each Forward Capacity Auction.

Q: What supply curves were used to evaluate the performance of the MRI-based sloped demand curves?

A: The ISO used three distinct sets of supply curves to evaluate the performance of the MRI-based sloped zonal demand curves. First, one set of models simply evaluate the performance of the curves at specific price levels. We refer to such models as “forward looking” as they are also consistent with equilibrium bidding behavior under the ISO’s two settlement capacity market design (also known as Pay for Performance). Under that design, the capacity supply curves are expected to be far more price-elastic (that is, flatter) in the vicinity of where the market clears than has been the case historically, where supply bids primarily reflected a resource's avoidable costs.

Second, we include a "historic bidding" (or "backward looking") supply model that constructs 1,000 simulated supply curves based on individual resource's observed supply bids/offers from FCA 7 through FCA 9. This second, "backward looking" model provides a useful contrast to the first set of "forward looking" models.

Third, with stakeholder input, we developed a set of supply offer models, based in part on observed resource supply data, that simulate supply resource entry and exit for 1,000 possible Forward Capacity Market outcomes. These supply offer models were evaluated for a range of possible long-run elasticities of supply in the Forward Capacity Market.

Q: Are there results for all three sets of supply models, for various performance measures?

A: Yes. The results for all three sets for supply models are provided in the detailed tables included as Attachment 1 to this filing, and discussed presently.

Q: Why did the ISO evaluate the performance of the Demand Curve Design Improvements using "forward looking" supply curves?

A: Under the Pay for Performance mechanism, competitive supplier bidding behavior in the Forward Capacity Auction implies that the supply curves should be relatively flat in the capacity region in which the market clears. We expect this will be increasingly evident as the Pay for Performance mechanism is phased in between now and FCA 15. The “forward looking” supply curves are consistent with this assumption as they use a perfectly elastic supply curve at a given price. These models therefore provide a useful guide about potential market outcomes under these supply bid/offer scenarios.

Q: What “forward looking” supply curves are included in the performance analysis?

A: We evaluated the performance of the sloped demand curves for numerous flat supply curves at various system and zonal price levels. These include supply offered at the FCA 10 Net CONE value of $10.81/kW-month (referred to as Model 1 in the results tables included in Attachment 1), as well as supply offered at the lower prices of $7.00/kW-month and $9.55/kW-month (Models 2a and 2b). The analysis also considers outcomes where supply is offered at $12.00/kW-month (Model 2c). Finally, we include a model where supply is offered at Net CONE in the Rest-of-Pool Capacity Zone, but is offered at 10 percent above this price in import-constrained zones (Model 2d).

Each of these first set of models is deterministic, meaning no simulated entry or exit is conducted for this set of supply curves. With a flat supply curve in the vicinity of the market clearing price, the market will always clear at the system capacity quantity where the demand curve reflects this supply price. For example, Model 1 will therefore always clear at a price of $10.81/kW-month and at quantities that correspond to this total price for all capacity zones.

Q: Do the "forward looking" supply models also consider instances in which the Net CONE value is modified from its FCA 10 value of $10.81/kW-month?

A: Yes. Models 4a and 4b consider outcomes in which Net CONE is decreased and increased by 20 percent relative to its FCA 10 value, and all capacity is offered at this new Net CONE value. Model 5a considers the case in which Net CONE is higher in import-constrained zones by 20 percent, but it is unchanged in the Rest-of-Pool Capacity Zone, and all supply is offered at the Net CONE value applicable to each zone.

Q: Why did the ISO also evaluate the performance of the Demand Curve Design Improvements using "historic" supply curves?

A: While the "forward looking" supply curves are most informative if competitive suppliers bid in a manner consistent with the ISO's two-settlement capacity market design in the future, it is also useful to consider simulated market outcomes if suppliers take many years to adjust their bidding behavior and therefore do not modify their bidding behavior from previous auctions. This is done with the "historic bidding" supply curves. Furthermore, because the "historic bidding" supply curves include 1,000 simulations, they may be informative in understanding the market volatility associated with the Demand Curve Design Improvements.

Q: How were these "historic" supply curves derived?

A: To calculate each of the 1,000 simulated "historic bidding" supply curves, we randomly sample from the population of individual resources' supply offers over three earlier auctions. More specifically, for each resource and simulation, the methodology randomly selects between its supply offers in FCA 7, 8 and 9 with equal probability. If a specific resource has a supply offer of $5.00/kW-month in FCA 7, $6.00/kW-month in FCA 8, and $7.00/kW-month in FCA 9, for example, then each of these offers will be used with one-third probability in each simulation.

This sampling occurs independently across resources, meaning for a given simulation, which auction price is selected for resource A's supply offer will not impact which auction price is selected for resource B's offer. Each "historic bidding" simulation then takes the selected supply offers from all of the resources in the market and constructs a supply curve for each capacity zone.

Q: Were the historic supply curves adjusted to yield average clearing prices in the range of Net CONE?

A: No. While the "forward looking" models were broadly designed to be consistent with Net CONE or possible future changes in the value of Net CONE, the "historic bidding" supply model was not. Instead, it is intended to represent how the MRI-based sloped zonal demand curves would perform if capacity suppliers continue to participate in the market in a manner consistent with recent history.

Q: Why did the ISO also evaluate the performance of the Demand Curve Design Improvements using a third set of supply models, simulating entry and exit?

A: The first set of "forward looking" supply curves are flat by design, to study the effects of clearing at specific price levels at current or possible future Net CONE values. The "historic bidding" supply curves tend to be quite steep, as this shape is consistent with the supply offers observed in the first two auctions used in the historic data sample (*viz.*, FCAs 7 and 8). Stakeholders input and discussion lead us to develop additional analyses that simulated a range of upward sloping supply curves that were less steep than the historical supply curves, and captured the potential for significant entry and exit from year to year. These supply curves therefore fall between the flat "forward looking" curves and the very steep "backward looking" ("historic bidding") supply models.

Q: Please provide more detail on how the third set of supply models with upward sloping supply curves that allow entry and exit are constructed.

A: The supply curves are constructed by first randomly sampling from all resources' qualified capacity quantities for FCA 10 to get simulated resources supply quantities, or "blocks." We then construct a base curve in two steps. The first step assigns prices for each of these simulated resource supply blocks to ensure that the base supply curve has an assumed average slope over a broad range above and below Net CONE. The second step adds inframarginal supply to ensure that the base supply curves intersect the sloped zonal demand curves at quantities that yield clearing prices in each zone equal to Net CONE ($10.81/kW-month). This is consistent with the Forward Capacity Markets intended equilibrium outcome and the sustainability design principle, which requires the market clear on average at a price equal to new resources' net cost of entry.

After constructing the base curves as described above, the third set of supply models introduce entry and exit in each of 1000 simulations. In each simulation, the method randomly selects some number of "new" resources to potentially enter the market by offering to supply capacity at randomly determined prices and quantities (within a reasonable range given by the base curves). Such offers will tend to shift the supply curve to the right, at various entry price points. Additionally, the method randomly selects resources to exit the market by removing their capacity supply offers from the supply curve. This will tend to shift the supply curve to the left. The resulting set of 1,000 simulated curves will have a similar overall shape to the base curve, but will differ to reflect the additional supply bids associated with potential entrants and the removal of other supply bids for resources exiting the market.

Q: For this third set of simulated supply models, what average slopes and entry and exit parameters were considered?

A: We derived 1,000 simulated supply curves for three different sets of parameters. Models 6a and 6b (*see* Attachment 1) each randomly allow between 0 and 10 resources to potentially enter or exit the market; the only difference between these two supply models is that the average slope is less steep in Model 6a than 6b. More specifically, Model 6a assumes an average supply curve slope of 0.003 $ per MW in the Rest-of-Pool Capacity Zone, and 0.0045 $ per MW in the Southeast New England Capacity Zone. Model 6b instead uses slopes of 0.005 and 0.0075 respectively (in $ per MW). Model 6c introduces even steeper average slopes of 0.008 and 0.012 (in $ per MW) for Rest-of-Pool Capacity Zone and the Southeast New England Capacity Zone, respectively. Furthermore, Model 6c now allows up to 30 resources to potentially enter and exit the market.

To interpret these slopes, an average supply curve slope of 0.003 $ per MW in the Rest-of-Pool Capacity Zone will lead the price specified by the aggregate supply curve to increase by an average of $0.30/kW-month with each 100 MW of capacity. This can be verified by multiplying the slope (0.003 $ per MW) by the change in quantity (100 MW) to get this change in price. Correspondingly, as this average supply curve slope becomes larger, the change in price associated with an additional 100 MW will increase. Broadly speaking, the slopes of the aggregate system supply curve used in Model 6 range from somewhat less steep to roughly comparable to that observed in historical data.

This simulation approach enables an assessment of the volatility of the clearing prices and quantities across all 1,000 simulations, although these volatility measures are dependent upon the supply modeling assumptions as well as the slopes of the MRI-based demand curves for the system and zones.

Q: Can you provide more detail about what the upward sloping simulated supply curves that allow entry and exit look like?

A: Figure 14 shows a representative set of ten of the 1,000 simulated system supply curves, as well as the MRI-based sloped system demand curve (using FCA 10 system planning parameters). While the shape of each curve simulated supply curve is generally similar, they intersect the demand curve at different prices and quantities based the simulated entry and exit decisions.

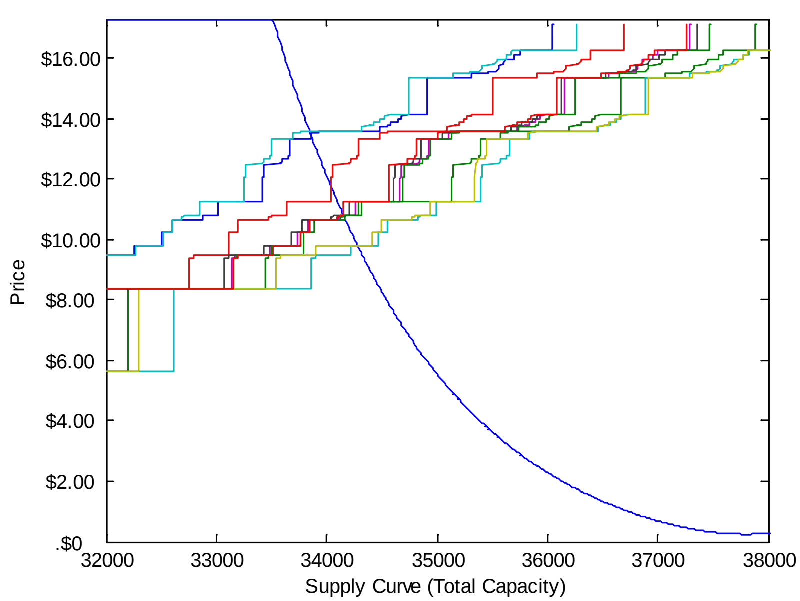

Figure 14

Q: What assumptions were used to derive the demand curves used in this analysis?

A: The demand curves were derived using the same system planning parameters as were used in FCA 10 and the applicable Net CONE value of $10.81/kW-month. There is one modeled import-constrained capacity zone, Southeast New England. The resulting MRI-based sloped demand curves are therefore equivalent to those provided in Figures 3 and 5 in Section V.

Q: What assumptions are used to determine the clearing prices and quantities for the various supply models?

A: In general, the clearing price is equal to the marginal resource's supply offer price. For example, in Model 1, where we assume that the supply curve is flat at Net CONE of $10.81/kW-month, the clearing price in both the Rest-of-Pool Capacity Zone and the Southeast New England Capacity Zone is equal to $10.81/kW-month. The cleared system capacity is equal to the system demand curve quantity that corresponds to the clearing price. To determine the cleared quantity in the Southeast New England Capacity Zone, we employ the same logic. Recall from Section V.C that the clearing price paid to resources in Southeast New England is the sum of the price paid in the Rest-of-Pool Capacity Zone and the zonal congestion price specified by the MRI-based zonal demand curve for the Southeast New England Capacity Zone. For the "forward looking" supply models that have a clearing price in Southeast New England equal to that in Rest-of-Pool

Capacity Zone, we assume that the cleared quantity is the import-constrained zone is the lowest capacity quantity that yields a congestion price of $0.00/kW-month.

For both the "historic bidding" supply model (Model 3) and the upward sloping simulation supply models modeling entry and exit (Model 6a-6c), we separately calculate the clearing prices and quantities for each of the 1,000 simulated supply curves. We assume that the marginal supply offers are rationable in this modeling, and use a market clearing algorithm that maximizes social surplus consistent with the Forward Capacity Auction.

Q: How is the resulting system LOLE value calculated for each supply model and simulation?

A: In general, the ISO's full-scale reliability planning simulation model that is used to calculate expected energy not served and MRI values for various system and zonal capacity levels also produces a number of other reliability-related performance metrics, including the LOLE value. These LOLE values account for the share of capacity in each modeled Capacity Zones, the total cleared system capacity, and the modeled zonal interface transfer capability. We use these data to estimate the LOLE associated with the cleared capacity levels (system and zonally) for each supply curve modeled.

More specifically, for each supply curve and simulation, we calculate the total LOLE as the sum of two values, as described in the discussion of LOLE calculations under unconstrained and constrained conditions in Section VII.C. That is, the first value is the LOLE that corresponds with the cleared system capacity without considering any zonal interface constraints. This value decreases as more capacity is procured at the system level. The second LOLE value accounts for the *additional* LOLE due to zonal interface constraints between capacity zones. This value decreases as the share of total system capacity that is cleared in the Southeast New England Capacity Zone increases and, at high capacity levels in the import-constrained zone, it will be equal to zero (which indicates the reliability planning simulation model projects there is no measurable likelihood of lost load due to solely to insufficient capacity in the Southeast New England Capacity Zone).

Q: Please provide a more detailed description of the reliability performance metrics for each supply model.

A: The reliability performance metrics for the sloped zonal demand curves under each set of supply models are described using three detailed numerical tables. The tables are included as Attachment 1 to the testimony.

The first of these tables reports various outcomes for the MRI-based demand curves, based on the FCA 10 zonal configuration and system planning parameters, for the system as a whole. The performance statistics reported in this table include the system LOLE metric that accounts for both system and local events, and the corresponding “1-day-in-X” value (this is the reciprocal of the LOLE value). It also includes information on the cleared system capacity and estimated total market payments. For the supply models that use 1,000 simulations, these results include not just the average values, but information on the distribution of these values. More specifically, they include the standard deviation of cleared capacity, the probability of low reliability outcomes (the percentage of simulations that yield an LOLE above 0.2 and the percentage of simulations that clear less system capacity than the Net ICR quantity), and additional information on the variation in total market payments across the 1,000 simulations.

The second table provides more detailed information on the performance of the MRI-based sloped zonal demand curves in the Southeast New England Capacity Zone. This includes the zone's contribution to the total LOLE value. Further, it includes data on the average clearing prices and quantities in the zone. For the supply models that include 1,000 simulations, the table provides additional information about the distribution of clearing prices and quantities. These include the standard deviation of both clearing prices and quantities, and the probability of various outcomes across the 1,000 simulations – such as clearing less capacity than the current Local Sourcing Requirement in the zone, clearing at a higher price than in the Rest-of-Pool Capacity Zone, and clearing with a zonal clearing price at the FCA's maximum price of $17.296/kW-month.

The third table reports additional information on clearing outcomes in the Rest-of-Pool Capacity Zone. This table includes clearing prices and quantities in the zone. For the supply models with 1,000 simulations, the table also provides the standard deviation of each of these variables, and the probability of clearing with a price in the Rest-of-Pool Capacity Zone at the FCA's maximum price of $17.296/kW-month.

Q: Please provide an overview of the performance of the MRI-based sloped zonal demand curves across this array of supply models.

A: For the majority of supply models considered, the sloped zonal demand curves produce outcomes that meet or exceed the "1-day-in-10" LOLE reliability criterion. In cases where the supply models yield average clearing prices that exceed Net CONE, the models tend to clear less capacity (due to the downward sloping demand curves); as a result, these cases have slightly lower overall reliability. However, even in such cases, the Design Curve Design Improvements continue to produce outcomes where system reliability is close to the "1-day-in-10" LOLE. This indicates that even in situations where exceptionally tight supply conditions lead to high capacity clearing prices and outcomes "high up" on the sloped capacity demand curves, these MRI-based demand curves continue to produce market clearing outcomes that exhibit reliability performance close to "1-day-in-10" LOLE reliability planning objective. Fundamentally, this occurs because with the convex MRI-based demand curves, the curves become increasingly steep as the level of capacity declines at high capacity prices; that, in turn, attenuates the potential reduction in cleared capacity when the market sets high prices, and limits the potential for the capacity market to clear quantities that would produce adverse reliability outcomes.

Q: Please describe the performance of the sloped zonal demand curves under Model 1, where the supply curve is flat at the Net CONE value.

A: When the marginal supply is offered at the Net CONE value of $10.81/kW-month in both the Southeast New England Capacity Zone and Rest-of-Pool Capacity Zone, the sloped zonal demand curves clear exactly enough capacity in the system and constrained zone to yield a LOLE value of 0.1, the "1-day-in-10" level. This is consistent with a system cleared quantity of 34,151 MW, which is equal to the Net ICR value for FCA 10, and its reported system LOLE value of 0.100. This result therefore indicates that the sloped zonal demand curves perform well in this benchmark case where the market's clearing price reflects Net CONE.

Q: How do the sloped zonal demand curves perform if clearing prices are below Net CONE?

A: The results also consider supply curves where capacity is offered at prices that are lower and higher than Net CONE. Model 2a considers outcomes if offers instead come in at a price of $7.00/kW-month, and Model 2b considers outcomes if offers come in at a price of $9.55/kW-month (which was the Rest-of-Pool Capacity Zone clearing price in FCA 9). In each, the cleared system capacity increases relative to the Model 1 result and the system is more reliable than the "1-day-in-10" LOLE criterion. More specifically, when clearing prices are $7.00/kW-month, the sloped zonal demand curves produce a system LOLE of 0.070 (1-day-in-14.3), and when clearing prices are $9.55/kW-month, the LOLE is equal to 0.090 (1-day-in-11.1).

This outcome is consistent with the intent of the Demand Curve Design Improvements, which were designed to procure different capacity quantities depending on the offer prices of supply. When the marginal cost of procuring capacity decreases (as in Models 2a and 2b relative to Model 1), the curves will purchase more capacity and system reliability will be higher.

Q: How do the sloped zonal demand curves perform if clearing prices are above the Net CONE value?

A: If capacity supply prices increase above Net CONE, the sloped demand curves will procure less capacity relative to Model 1. This outcome is observed in Models 2c and 2d. In Model 2c, the supply curve is assumed to be flat at $12.00/kW-month, which is 11 percent above Net CONE. In this instance, the market would clear slightly less system capacity than Model 1 (34,011 MW rather than 34,151 MW), and the estimated system LOLE value would be 0.110 (one-day-in-9.1), which is slightly worse than the “1-day-in-10” LOLE criterion.

Model 2d introduces a modification to the flat supply model as it assumes that supply in the Rest-of-Pool Capacity Zone is offered at the Net CONE value of $10.81/kW-month, but supply in the Southeast New England Capacity Zone is offered at a price 10 percent higher. In this case, the market will clear the same quantity of system capacity as in Model 1. But because capacity in the Southeast New England Capacity Zone is offered at a higher price, the market will no longer clear at the quantity that produces a congestion price of $0.00/kW-month. Instead, the market would clear at the quantity that produces a zonal congestion price equal to 10 percent of the Net CONE (or $1.08/kW-month in this instance). This will lead the market to clear less capacity in the Southeast New England Capacity Zone. Rather than clearing the quantity that corresponds with a congestion price of $0.00/kW-month (10,880 MW), the market will now clear the quantity that corresponds to a price of $1.08/kW-month (9,946 MW).

Despite no change to total cleared system capacity, the decrease in the capacity cleared in the Southeast New England Capacity Zone will lead to slightly worse system reliability than in the "benchmark" case in Model 1. This decrease in LOLE relative to Model 1 occurs because, much like how transferring capacity from the Rest-of-Pool Capacity Zone to the Southeast New England Capacity Zone may improve system reliability when the import-constrained zone is relatively short (as outlined in Section V), transferring some capacity from the Southeast New England Capacity Zone to the Rest-of-Pool Capacity Zone – in response to the relatively higher price in the import-constrained zone – results in slightly lower overall system reliability.

Q: Do the reliability results from Models 2c and 2d indicate that the sloped zonal demand curves do not satisfy the reliability principle?

A: No. The reliability performance of any set of sloped demand curves is dependent on the supply conditions modeled, and it is always possible to construct supply curves that represent tight conditions and high price levels for which cleared capacity levels in the FCA – when using downward-sloping demand curves instead of fixed requirements – may fall below the "1-day-in-10" LOLE criterion. The results in Models 2c and 2d suggest that if Net CONE consistently underestimates the true cost of new entry, then the proposed curves may perform slightly worse than the "1-day-in-10" LOLE criterion. However, even in these cases, the sloped zonal demand curves would continue to deliver reliability levels that are close to the "1-day-in-10" LOLE criterion (as the results indicate that Model 2c would deliver 1-day-in-9.1 LOLE and Model 2d would provide 1-day-in-9.2 LOLE).

Moreover, such a situation would appropriately indicate that the Net CONE value should be upwardly revised. Since this value is used to set the MRI-based demand curves (via the calculation of the scaling factor, as described in Section V.B), a proper revision of Net CONE would result in MRI-based demand curves that again satisfy the "1-day-in-10" LOLE criterion. Stated differently, the MRI-based demand curve methodology always satisfies the reliability principle (by design), but the actual reliability achieved in any given year will depend on actual market clearing outcomes; over time, the value of Net CONE with which the

MRI-based curves are calibrated must be revised, as needed, to ensure it remains a reasonably accurate measure of resources' true net cost of new entry.

Q: How do the Demand Curve Design Improvements perform if Net CONE is increased or decreased from its FCA 10 value?

A: Models 4a, 4b, and 5a consider cases in which Net CONE is assumed to be revised from its FCA 10 value of $10.81/kW-month. In each case, the supply curve is assumed to be flat at this updated Net CONE value, providing information on market outcomes if the capacity market clears at these alternative price levels. Importantly, and consistent with the overall MRI-based demand curve designs, in Models 4a, 4b, and 5a we assume that the MRI-based demand curves are similarly updated based on the revised Net CONE value studied in each of these models.

As the results show, the market clears sufficient capacity to satisfy the system "1-day-in-10" LOLE criterion in each of these instances. This outcome occurs because the Demand Curve Design Improvements derive an updated scaling factor to ensure that if each zone clears at its revised Net CONE value, the cleared capacity will satisfy the region's reliability planning objective.

Q: In Model 5a, why does the market clear more than the Net ICR value?

A: In Model 5a, the supply curve in the Rest-of-Pool Capacity Zone is flat at the Net CONE value of $10.81/kW-month. However, in the Southeast New England

Capacity Zone, the supply curve in this model is flat at the higher price of \$12.97/kW-month to reflect that entry and Net CONE are assumed (in this scenario) to be more expensive in this import-constrained capacity zone.

Recall from Sections IV and VI that the cost-effectiveness design principle ensures that the curves will clear capacity in a manner that minimizes the total bid-cost for the level of system reliability achieved. When comparing Model 5a to Model 1, the absolute cost of capacity in the Southeast New England Capacity Zone is greater while the absolute cost of capacity in the Rest-of-Pool Capacity Zone is unchanged. In relative terms, this means that capacity in the Southeast New England Capacity Zone has now become more expensive and capacity in the Rest-of-Pool Capacity Zone has become less expensive.

Because supply offers come in at the Net CONE values in both Models 1 and 5a, each will produce an outcome that meets the "1-day-in-10" LOLE criterion (because the demand curve scaling factors are selected to ensure as much, given Net CONE). To meet the cost-effectiveness property for both models, the cleared capacity quantities in each zone should ensure that the marginal reliability impact of capacity is proportional to the clearing price. In Model 1 where capacity is paid the same price in the Rest-of-Pool Capacity Zone and Southeast New England Capacity Zone, this leads to the clearing of sufficient capacity in the Southeast New England Capacity Zone to ensure that its marginal reliability impact is no greater than that for capacity in the Rest-of-Pool Capacity Zone.

However, because capacity clears at a 20 percent premium in the Southeast New England Capacity Zone in Model 5a (due to the higher assumed Net CONE in that constrained zone in this scenario), the marginal reliability impact of capacity in the zone will also be 20 percent greater than for capacity in the Rest-of-Pool Capacity Zone.

As a result, to satisfy the cost-effectiveness design principle, the sloped zonal demand curves will substitute away from where capacity has become relatively more expensive (the Southeast New England Capacity Zone) and towards where it has become relatively less expensive (the Rest-of-Pool Capacity Zone). However, as the market substitutes away from the Southeast New England Capacity Zone and toward Rest-of-Pool Capacity Zone, the substitutability can no longer be at a 1 MW-for-1 MW rate, because each additional increment of capacity in the Southeast New England Capacity Zone has a greater marginal reliability impact. For each MW no longer cleared in the Southeast New England Capacity Zone, the curves must therefore clear more than 1 MW in the Rest-of-Pool Capacity Zone. This will lead the total cleared system capacity to increase above the Net ICR value, as is shown in Model 5a. This outcome is shown in Model 5a's total cleared capacity of 34,393 MW, which exceeds the Net ICR value of 34,151 MW.

Q: Please describe the performance of the sloped zonal demand curves under the "historic bidding" supply model.

A: Model 3, the "historic bidding" supply model, uses 1,000 simulations drawn based on supply offers from FCAs 7 through 9. Consistent with outcomes in these recent auctions, the sloped zonal demand curves clear more than enough capacity to meet the "1-day-in-10" LOLE criterion. More specifically, with the "historic bidding" supply model, the MRI-based sloped demand curves would produce an average system LOLE of 1-day-in-13, and clear 449 MW in excess of Net ICR.

While a small percentage of the simulations would produce cleared system quantities below Net ICR, there were no cases among the 1,000 simulations where the cleared capacity quantities produced a system that had a worse (higher) LOLE value than 0.2 (1-day-in-5).

In Model 3, average clearing prices in the Southeast New England Capacity Zone are $7.90/kW-month, which is $0.05/kW-month greater than those in the Rest-of-Pool Capacity Zone. While this difference is small, the market yields a positive congestion price for the Southeast New England Capacity Zone in 36 percent of the 1,000 simulations. This pair of summary statistics indicates that even when Southeast New England has a higher price, its price premium tends to be small. For both zones, the standard deviation of clearing prices is in the range of $1.80/kW-month.

Q: How are the Model 3 results informative about the sloped zonal demand curves, moving forward?

A: Because the "historic bidding" supply model constructs simulated supply curves based on historical bids and offers, the resulting outcomes should be broadly consistent with those observed in previous auctions. We find this to be the case as the system has tended to clear capacity in excess of the Net ICR in recent auctions. As a result, if bidding behavior going forward is largely consistent with that from previous auctions, we can expect that the sloped zonal demand curves will easily satisfy the system's "1-day-in-10" LOLE criterion.

Q: Please describe the performance of the sloped zonal demand curves under the upward sloping supply curves with entry and exit in Models 6a through 6c.

A: In each of these supply models, the average cleared system capacity across the 1,000 simulations falls below Net ICR by a small amount (between 24 MW and 73 MW), and average system reliability is slightly below the "1-day-in-10" LOLE (ranging from 1-day-in-9.4 to 1-day-in-9.8). Consistent with clearing less capacity than Net ICR, average prices are slightly greater than Net CONE. In each case, a steeper assumed average supply curve slope produces slightly worse average LOLE values, and slightly higher average prices.

Q: Are the performance outcomes in Model 6 cause for concern?

A: No. The Model 6 supply curve analyses were introduced to test the robustness of the sloped zonal demand curves to more scenarios when the supply curves are upward sloping at progressively steeper average slopes (from Model 6a to Model 6c), and there are potentially a large number of resources entering or permanently exiting from one auction to the next.

If the average results in these supply models were to deviate substantially from those provided in Model 1, it would indicate that the MRI-based sloped demand curves may not be robust to changes in the markets supply conditions over time. However, the results instead show that when much more elaborate supply conditions are explicitly modeled, including entry/exit and a wide range of different average supply slopes (elasticities), the MRI-based sloped zonal demand curves continue to deliver reasonable reliability performance.

Q: Was the performance of the zonal demand curves evaluated under alternate zonal configurations?

A: Yes. To ensure that the MRI-based demand curve design is robust to potential changes in zonal configurations, we evaluated the performance of the sloped zonal demand curves for a number of zonal configurations. Among those considered is a scenario in which the system has both an import-constrained zone in Southeast New England and an export-constrained zone in Northern New England (as discussed previously in Section V.D).

Additionally, we considered a scenario in which there were multiple smaller import-constrained zones, consistent with the zonal configuration used in FCA 9. In that auction, there were three import-constrained capacity zones modeled: Connecticut, Northeast Massachusetts/Boston, and Southeast Massachusetts/Rhode Island. This zonal configuration allows for the evaluation of the sloped zonal demand curves when the system has multiple smaller import-constrained capacity zones.

Q: How did the performance of the sloped zonal demand curves under these alternate zonal configurations compare to that for the results presented that used the FCA 10 zones?

A: Broadly speaking, the performance of the sloped zonal demand curves was similar to the outcomes for the FCA10 zonal configuration. As with the results presented earlier in this section and in Attachment 1, the MRI-based demand curves result in market outcomes that meet or exceed the reliability objective in most supply models, and for the models that represent more extreme or stressed supply conditions, the differences between the outcomes and "1-day-in-10" LOLE criterion remain slight. Broadly, we conclude that the MRI-based demand curves perform consistently and as expected under a wide range of alternative zonal configurations, including multiple constrained zones, an export-constrained zone, and smaller import-constrained zones.

Q: Was analysis conducted to determine how the Demand Curve Design Improvements performed relative to a design that retains the existing linear system demand curve?

A: Yes. At stakeholder request, we used the various supply models discussed above to evaluate average market outcomes for a scenario in which (1) the MRI-based zonal demand curves are used in constrained zones, and (2) the existing linear system demand curve is retained (that is, there is no system-level MRI-based demand curve). As was demonstrated in Section VI, it is known that this scenario cannot procure capacity cost-effectively, so total bid-costs (and total market payments) will be greater under this scenario than if the Demand Curve Design Improvements are applied and all zones and the system curve are MRI-based. However, the magnitude of the greater market payments depends on the market supply conditions.

Across the range of the supply models studied, this "hybrid" demand curve produced a wide range of potentially higher total market payments. At the low end, retaining the existing linear system demand curve would increase estimated total market payments by approximately $50 million per year (Model 1). At the high end, retaining the existing linear system demand curve would increase estimated total market payments by approximately $300 to $500 million per year (a range obtained using Models 3 and 6a-6c). This broad range of potential outcomes makes it difficult to assert with confidence what the actual impact of retaining the existing linear system demand curve would be on total market payments. However, it confirms empirically what we know on the basis of economic theory and sound market design: Unless MRI-based demand curves are used to procure capacity in the Forward Capacity Auction, the capacity market will continue to fail to procure capacity cost-effectively.

IX. THE DEMAND CURVE DESIGN IMPROVEMENTS ALLOW FOR THE ELIMINATION OF THE ADMINISTRATIVE PRICING RULES THAT WERE INTRODUCED TO ADDRESS ISSUES ASSOCIATED WITH THE USE OF VERTICAL ZONAL DEMAND CURVES

Q: What administrative pricing rules currently are used in the Forward Capacity Market?

A: The Forward Capacity Market currently uses three administrative pricing rules that were developed to address market power and price volatility issues that can arise due to the vertical nature of the existing zonal demand curves.

The first two administrative pricing rules – the Insufficient Competition and Inadequate Supply rules – are used to limit the price paid for existing resources when supply conditions in an import-constrained zone are tight. These rules were introduced to limit the costs to consumers when circumstances might allow capacity suppliers to exercise market power.

The third administrative pricing rule – the Capacity Carry Forward Rule – is used to limit the potential for prices to drop significantly in an import-constrained capacity zone following an auction in which the clearing of a "lumpy" (non-rationable) new resource has resulted in the zone having supply that significantly exceeds its requirement for a period of time. Again, this administrative pricing rule was necessary due to the vertical nature of the existing zonal demand curves and their potential to produce dramatic price swings in response to small changes in supply.

Q: Why does the use of sloped zonal demand curves help to eliminate the need for the Inadequate Supply and Insufficient Competition rules?

A: The Inadequate Supply and Insufficient Competition rules were designed to help address market power concerns. However, the use of the MRI-based sloped zonal demand curves and related changes to the capacity market rules address market power concerns in three important ways and, thereby, eliminate the need for these special pricing rules.

First, the use of sloped, as opposed to vertical, zonal demand curves provides market power protection by reducing the ability and incentive for a capacity supplier to raise prices by withdrawing a resource from the market. Obviously, when vertical curves are used and market conditions become tight, the withdrawal of a resource could have a large and dramatic impact on prices. However, when curves are sloped the price impact of any withdrawal is more gradual and attenuated.

Second, the Demand Curve Design Improvements allow for greater substitution of capacity between zones by, for example, potentially allowing an auction to procure more relatively low-priced resources located in the Rest-Of-Pool Capacity Zone instead of procuring relatively high-priced resources in an import-constrained capacity zone. As noted in Section VII, the MRI-based demand curves allow this substitution to take place in a cost-effective manner while still achieving reliable outcomes. From a market power mitigation perspective, this substitutability means that resources within an import-constrained capacity zone face additional competition from resources located outside the zone and, therefore, have less ability to exercise market power.

Finally, the Forward Capacity Auctions use of a "maximize social surplus" principle when clearing non-rationable ("lumpy") supply bids/offers further mitigates the potential exercise of market power in an import-constrained capacity zone.[16] Under the existing rules, the fixed zonal requirement represented by vertical demand curves can result in a very high-priced marginal resource clearing the auction even if only a small portion of the resource is needed to meet the zonal requirement. Under the Demand Curve Design Improvements, however, the auction's existing objective to maximize social surplus will serve to further reduce the potential for market power, because if a resource's offer price is "too high" (due to attempted market power) there is a greater likelihood that the resource will not clear the market. Specifically, with sloped demand curves, the auction's objective to maximize social surplus is less likely to be achieved if only a small portion of resource is needed to meet demand (given resource offers and

[16] *See* ISO Tariff Section III.13.2.7.4.

delist bids are typically non-rationable) – that is, the portion of a non-rationable resource offer's capacity that 'overhangs' (extends past) the demand curve counts *against* that resource's contribution to social surplus, making it less likely to clear if it raises price (again, relative to the current fixed zonal demand curves). Thus, attempting to exercise market power by raising prices in tight conditions is less likely to be successful.

For the reasons just discussed, the use of the MRI-based demand curves will significantly reduce the potential for a capacity supplier to successfully exercise market power in an import-constrained capacity zone. With these new protections in place, it is appropriate to remove the Insufficient Competition and Inadequate Supply rules for import-constrained capacity zones, just as they were removed at the system level when a sloped system-wide demand curve was adopted.[17]

As recognized by both the ISO's Internal Market Monitor and External Market Monitor, concerns about the potential exercise of market power in the Forward Capacity Market also have been reduced by other recent rule changes.[18]

Specifically, the ISO's two-settlement capacity market design (also known as Pay for-Performance) is expected to result in increased supply elasticity in the region

[17] *ISO New England Inc. and New England Power Pool Participants Committee, Order Accepting Tariff Revisions,* 147 FERC ¶ 61,173 at P 29 (2014) (the "May 30, 2014 Order"), *Order Denying Rehearing, Providing Clarification and Directing Further Compliance Filing,* 150 FERC ¶ 61,065 (2015).

[18] See Attachments 3 and 4, respectively.

where the market clears, which will further reduce price volatility. In addition, in Docket No. ER15-1650, the Commission accepted rule changes to improve the Internal Market Monitor's ability to review and mitigation certain de-list and capacity import bids. Finally, the ISO recently proposed, and the Commission accepted, important changes to mitigate the potential for market power to be exercised through an "uneconomic retirement."[19] All of these changes that help to address concerns about the potential to exercise market power in the capacity market help to reduce the need for the Insufficient Competition and Inadequate Supply rules.

Q: Why does the use of sloped zonal demand curves eliminate the need for the Capacity Carry Forward Rule?

A: The Capacity Carry Forward Rule was implemented to address price volatility concerns that arise due to vertical demand curves in import-constrained capacity zones – specifically the potential for prices to fall significantly in the years following the entry of a large, new resource. With the introduction of the MRI-based sloped zonal demand curves, prices will no longer be susceptible to such dramatic decreases following new entry because demand falls gradually in response to increases in surplus capacity under the new zonal demand curves. By design, the prices at any point on the demand curve provide an accurate reflection of the marginal reliability impact of capacity. If the price falls following an

[19] *ISO New England Inc., Order Accepting Tariff Filing Subject to Condition*, 155 FERC ¶ 61,029 (2016).

auction in which there was new entry, it will be to a level that reflects the marginal reliability of capacity at that point. Accordingly, under the Demand Curve Design Improvements, the Capacity Carry Forward Rule is no longer required to address price volatility concerns and should be eliminated.

X. ADDITIONAL IMPORTANT FEATURES OF THE DEMAND CURVE DESIGN IMPROVEMENTS

A. <u>Transition Period with a Modified System Demand Curve</u>

Q: Explain the transition from the existing linear System-Wide Capacity Demand Curve to the new MRI-based system curve.

A: The new System-Wide Capacity Demand Curve will be implemented according to a transition mechanism from the existing linear demand curve design to the new MRI-based sloped demand curve design. During the transition period, the System-Wide Capacity Demand Curve is a hybrid of the existing linear demand curve design used in FCA 10 and the new MRI-based design. The duration of the transition period (referred to as the MRI Transition Period and defined in Section III.13.2.2.1 of the market rules) cannot exceed three years, meaning the full MRI-based system demand curve will be in place no later than FCA 14. However, it is possible that the MRI Transition Period may end, and the full MRI-based system demand curve be implemented, earlier than FCA 14 if certain conditions relating to the change in Net ICR in future auctions, relative to the Net ICR in FCA 10, are met.

Q: Describe the shape of the System-Wide Capacity Demand Curve during the MRI Transition Period.

A: During the MRI Transition Period, the System-Wide Capacity Demand Curve (hereafter, the "transition curve") uses a combination of design elements drawn from the system-wide demand curve that was used in FCA 10 and from the new MRI-based system demand curve design. The transition curve has three segments that are based, in part, on the clearing price for New England in FCA 10 (which was $7.03/kW-month).

The first segment uses the same price-quantity pairs as the MRI-based system demand curve that will be applicable to each Forward Capacity Auction, and determines the shape of the transition curve at prices above $7.03/kW-month and below the Forward Capacity Auction Starting Price.

The second segment of the transition curve is linear with the same slope as applied to the system demand curve in FCA 10. This second segment has a starting price at $7.03/kW-month and an ending price at $0.00/kW-month. Separate quantity values for the starting and ending prices are specified for FCA 11, FCA 12 and FCA 13; however, the same slope that was used for the system demand curve in FCA 10 is applied in each case. The second segment quantity values are specified to gradually shift this second segment to the left over the course of the transition period, so that by FCA 13 it more closely approximates the MRI-based system demand curve. To do so, the second segment's starting quantity, specifying the MW value at which this second segment begins (*i.e.* the quantity for which the linear curve specifies a price of $7.03/kW-month), is determined by two conditions. First, the starting quantity cannot exceed 35,437 for FCA 11, 35,090 for FCA 12 and 34,865 for FCA 13. Second, the transition curve specifies that this starting quantity cannot exceed the MRI-based demand curve value at $7.03/kW-month by more than 722 MW for FCA 11, 375 MW for FCA 12 and 150 MW for FCA 13.

The third segment of the transition curve is a horizontal line that specifies a price of $7.03/kW-month for all quantities between the first and second segments. The length of this horizontal line is limited because one of the conditions governing the second segment caps the MW difference between the capacity quantity specified by the second segment at a price of $7.03/kW-month, and that specified by the first segment at this same price. More specifically, the provision indicates that the length of this third segment cannot exceed 722 MW for FCA 11, 375 MW for FCA 12, and 150 MW for FCA 13.

Figure 15 below illustrates the transition curves for FCA 11, FCA 12, and FCA 13, assuming the MRI-based curve that corresponds to the FCA 10 system planning parameters (*i.e.*, no change in Net ICR) and the current value of Net CONE in the Tariff ($10.81/kW-month). To interpret, the transition curve applicable for FCA 11 follows the MRI-based curve (in blue color) from the auction starting price (currently $17.296/kW-month) down to a price of

$7.03/kW-month; then extends horizontally by 722 MW to the far-right downward sloping linear segment (in red color), which extends to the price of $0.00/kW-month. The transition curve applicable for FCA 12 again follows the MRI-based curve from the auction starting price to a price of $7.03/kW-month. However, its horizontal segment is shorter as only extends 375 MW to the downward sloping linear segment (in green color).

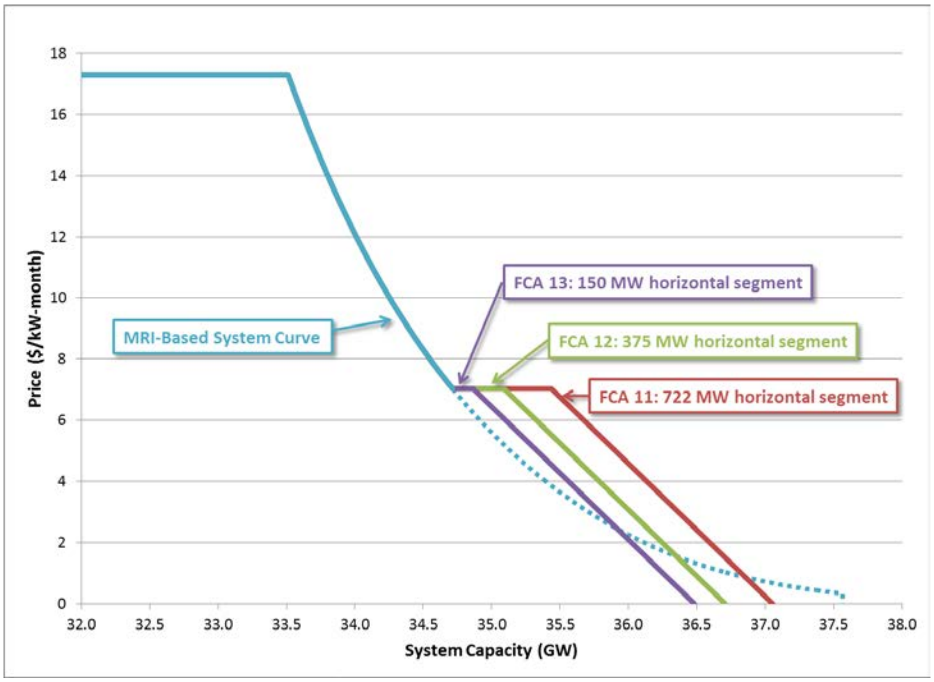

Figure 15

Q: Explain the conditions that determine the length of the MRI Transition Period.

A: The MRI Transition Period cannot extend beyond FCA 13. Furthermore, there are two conditions that could cause the MRI Transition Period to end earlier than FCA 13.

The first condition is set out in revised Section III.13.2.2.1(i). This condition considers the cumulative change in Net ICR since FCA 10. More specifically, the condition compares the Net ICR for each upcoming auction with the Net ICR for FCA 10, which was 34,151 MW. If the cumulative change in the Net ICR since FCA 10 exceeds 722 MW (for FCA 11), 375 MW (for FCA 12) or 150 MW (for FCA 13), then the MRI Transition Period is concluded and the full MRI-based system demand curve is used in all future auctions. The initial 722 MW threshold for FCA 11 reflects the length of the horizontal third segment of the transition curve for FCA 11 when applying the FCA 10 system planning and Net CONE parameters. Similarly, the 375 MW and 150 MW quantities reflect the length of this horizontal third segment when applying these same parameters to FCAs 12 and 13.

The second condition is set out in revised Section III.13.2.2.1(ii). This condition addresses an unlikely, but possible, outcome in which the transition curve could otherwise include a segment that is "backward-sloping" in that the quantity of demand at prices slightly above $7.03/kW-month is greater than the quantity of demand at prices slightly below $7.03/kW-month. This outcome could occur if the first segment of the transition curve (*i.e.,* the upper, MRI-based segment) were to shift significantly to the right due to a significant increase in (*e.g.*) the load forecast or Net CONE. To protect against such a possibility, the second condition indicates that in such cases, the MRI Transition Period is concluded. At a lesser right-shift of the first segment, the length of the horizontal third segment would simply be reduced because the difference between the quantities specified by the first and second segments at a price of $7.03/kW-month would decrease.

If neither of the two conditions is met before FCA 13, the MRI Transition Period concludes after that auction and the full MRI-based system demand curve is used for FCA 14 and future auctions. This provision is set out in revised Section III.13.2.2.1(iii).

B. <u>Modifications to Existing Rules Governing Auction Procedures</u>

Q: Are there any additional rule changes in the Demand Curve Design Improvements that are required to conform the existing rules to the new design?

A: Yes, the new MRI-based demand curves require several largely technical changes to the rules governing auction procedures. These changes relate to the truncation of the system and zonal demand curves at very low prices, conforming changes to the rules governing the closing conditions for auction rounds, and the calculation of surplus supply at the end of an auction round.

Q: Explain the truncation rules that will be applied to the new MRI-based curves.

A: In the absence of truncation rules, the MRI-based design can produce curves with very long "tails" that reflect the diminishing, near-zero impact of incremental capacity at high levels of capacity overall. Indeed, in theory, the MRI-based system demand curve tends toward zero as capacity tends toward infinity. Modeling a demand curve out to such unreasonably large system capacity levels is not practical.

From a practical perspective the capacity market will clear well before it reaches the far-right, extended portion of the "thin tails" of the MRI-based system demand curve. Accordingly, to avoid the numerical challenges of modeling near-zero demand curves at high capacity levels, the Demand Curve Design Improvements include rules for truncating the system and zonal curves at appropriately high capacity levels.

At the system level, the reliability improvement associated with adding incremental capacity diminishes at very high capacity levels. Therefore, the revised rules provide that the system curve will be truncated (meaning, set to a price of $0.00/kW-month) for quantities greater than 110% of Net ICR. This is provided in revised Section III.13.2.2.1. For comparison purposes, the current linear system curve truncates (meaning, produces a price of $0.00/kW-month) at a lower capacity level of approximately 108% of Net ICR.

Q: Are there similar truncation rules for the MRI-based zonal demand curves?

A: Yes. For import-constrained zones, the truncation rule is based on price rather than a percentage of the Local Sourcing Requirement. This is because the MRI-based demand curves do not have theoretical 'fixed' position relative to the Local Sourcing Requirement, and because relatively low but positive congestion prices are possible in zones (since the zonal price specified by the MRI-based demand curves for constrained zones represent a price premium above the price paid in the Rest-of-Pool Capacity Zone). Therefore, for import-constrained capacity zones, the truncation rule sets a price of $0.00/kW-month at quantities greater than the $0.01/kW-month price point. In other words, at quantities above the level where the zonal demand curve reaches $0.01/kW-month, the price will be set to $0.00/kW-month. The truncation rule for import-constrained zones is in revised Section III.13.2.2.2.

Similar to import-constrained zones, the truncation rule for export-constrained zones is based on price rather than a percentage of the Maximum Capacity Limit. For export-constrained capacity zones, the truncation rule sets a price of $0.00/kW-month at very low quantities: Specifically, quantities below the –$0.01/kW-month price point (recall that the prices specified by an MRI-based congestion price demand curve for an export-constrained zone are *negative* or zero). In other words, at quantities below the level where the export-constrained congestion price demand curve reaches –$0.01/kW-month, the price will be set to

$0.00/kW-month. The truncation rule for export-constrained zones is in revised Section III.13.2.2.3.

Q: What is the purpose of the round closing rules that are used in the Forward Capacity Market's Descending Clock Auction?

A: The round closing rules determine how long (how many rounds) the descending clock auction will continue. The descending clock auction must continue until enough information about supply resources' bids and offers has been collected to clear the market at both the system and zonal levels. Once enough information has been collected, the descending clock auction is concluded. At that point, the bid/offer information that has been collected is entered into the market-clearing software system to determine final capacity awards and prices that properly address awards to non-rationable ("lumpy") resource bids/offers, consistent with various market rules.[20]

Q: How do the round closing rules work under the existing capacity market design?

A: The existing round closing rules apply similar logic at the system and zonal levels. At the system level, where demand is represented by a sloped linear demand curve, the Rest-of-Pool Capacity Zone can be closed when end-of-round supply is less than end-of-round demand. The end-of-round supply at the system level includes supply from import-constrained zones at quantities at or above the

[20] *See, e.g.*, ISO Tariff Sections III.13.2.6, III.13.2.7.4.

Local Sourcing Requirement and supply from export-constrained zones at quantities that are no greater than the Maximum Capacity Limit. When the round closing conditions are met, there is enough information about the supply curve to determine which suppliers can be awarded a Capacity Supply Obligation.

For import-constrained zones, the existing rules provide that a zone may be closed when either: (i) the end-of-round quantity of supply is less than the end-of-round demand (equal to the Local Sourcing Requirement), or; (ii) the adjusted end-of-round system supply is less than the system end-of-round demand. Similar to with the system, when either of these conditions is met and the zone is closed, there is enough information about the supply curve in the import zone to determine which suppliers can be awarded a Capacity Supply Obligation.

For export-constrained zones, the existing rules provide that a zone may be closed when the end-of-round quantity of supply is less than the Maximum Capacity Limit and the Rest-of-Pool Capacity Zone is closed. Under the existing rules, the exclusion of any supply in excess of the export-constrained zone's Maximum Capacity Limit reflects the fact that it is not possible to clear more than this limit.

Q: Why is it necessary to revise the auction's round closing rules?

A: As explained earlier in the testimony, the use of the new MRI-based curves allows for a more cost-effective clearing of the market because capacity can be substituted between constrained zones and the rest of the system. As discussed in

Section VII, this capacity substitution effect also means that cleared quantities in each zone are now interdependent, because the outcome in one zone depends on the prices of bids/offers in the other zones as well. In other words, it may now be possible to achieve reliable outcomes by purchasing more than the demand "requirement" in one zone and less than the "requirement" in another zone (for example, by purchasing more than the Net ICR at the system level, but less than the Local Sourcing Requirement in an import-constrained zone). The current round closing rules which are based on fixed requirements do not fully account for this interdependency. Most importantly, if the round closing rules were not appropriately revised, the descending clock auction would not necessarily collect all of the bid/offer information required to clear the market as intended under the new design.

Q: How do the new round closing rules work for import-constrained zones?

A: Under the MRI-based curves, the amount of capacity cleared in an import-constrained zone will depend on the amount of capacity cleared in all of the other zones. More specifically, recall that the demand curve used in an import-constrained zone can be viewed as being "shifted up" based on the clearing price for the Rest-of-Pool Capacity Zone, because the zonal demand curve specifies a congestion price that will be added to the system price (*c.f.* Figure 12 in Section VII). However, at the end of an auction round, the clearing price for the Rest-of-Pool Capacity Zone may not yet be known. Accordingly, it is necessary to apply a conservative round closing rule for import-constrained zones that assumes the "lowest" possible level of system demand at the end-of-round price. This approach ensures that an import-constrained zone does not close prematurely because, if there is enough bid/offer information to close the import-constrained zone when there is a low system price, then there will also be enough bid/offer information to close the import-constrained zone at higher system prices.

The rules in revised Section III.13.2.3.3(a) account for this, by providing that an import-constrained zone is closed when one of two conditions is met: (1) the end-of-round supply in the zone is less than end-of-round demand in the zone assuming the lowest possible clearing price for the Rest-of-Pool Capacity Zone given the amount of supply remaining at the system and zonal levels at the end of the round, or; (2) the Rest-of-Pool Capacity Zone is closed. This is a conservative closing rule that ensures the descending clock auction will collect sufficient supply bids/offers from resources to avoid prematurely closing an import-constrained capacity zone during the Forward Capacity Auction.

Q: How do the new round closing rules work for the Rest-of-Pool Capacity Zone?

A: The zonal interdependencies discussed above also apply to the Rest-of-Pool Capacity Zone. The key difference is that the system demand curve is not "shifted up or down" based on zonal clearing prices. Instead, the quantity of capacity cleared at the system level may change depending on the quantity of capacity that clears in constrained zones.

More specifically, the auction may clear additional capacity offered at higher prices in an import-constrained zone because that capacity has a higher marginal reliability impact than lower-priced capacity located elsewhere. Accordingly, the round closing conditions must account for this potential, which requires modifications to the existing rules. The revised round closing conditions must consider that the auction no longer requires an import-constrained zone to clear its Local Sourcing Requirement and, instead, there may be cases where more or less capacity is cleared in the zone than the Local Sourcing Requirement (while still clearing the zone at a higher price than the price in the Rest-of-Pool Capacity Zone).

Similarly, the new design can result in cases in which some capacity in export-constrained zones can be excluded from the end-of-round evaluation for the Rest-of-Pool Capacity Zone because not all of the capacity in the export-constrained zone will be cleared. The current rules limit the quantity of capacity that can be counted toward the system requirement by the Maximum Capacity Limit (as this represents the maximum quantity of capacity that can be cleared in the zone). With the introduction of a sloped demand curve in the export-constrained zone rather than a fixed limit, the rules concerning the quantity of capacity in the export-constrained zone that can be counted in each round must be adjusted to account for the variability of the amount of capacity that may clear under a sloped zonal demand curve (since the quantity of capacity that can now be counted as contributing toward the system requirement can now be greater or less than the Maximum Capacity Limit).

For the reasons discussed above, the revised round closing rules for the Rest-of-Pool Capacity Zone in revised Section III.13.2.3.3(b) recognize that closing the auction at the system level now depends on whether the quantity of total system supply, adjusted to reflect that additional supply may be cleared in import-constrained zones and that less supply may be cleared in export-constrained zones, is less than system demand at the end-of-round price. Again, this is a conservative closing rule that ensures the descending clock auction will collect sufficient supply bids/offers from resources in the Rest-of-Pool Capacity Zone to avoid prematurely closing the Forward Capacity Auction.

Q: How do the new round closing rules work for export-constrained zones?

A: The round closing rules for export-constrained zones also are revised to reflect the zonal interdependencies that exist when using the MRI-based sloped demand curves. In the case of export-constrained zones, the revised round closing rules in revised Section III.13.2.3.3(c) provide that an export-constrained zone can be closed if both of the following conditions are met: (1) the amount of capacity remaining in the zone at the end-of-round price is less than the highest quantity of supply that is possible at a congestion price of $0.00/kW-month according to the zonal demand curve, or; (2) the Rest-of-Pool Capacity Zone is closed. As with the other revised zone closing rules, this is a conservative approach to ensure that an export-constrained zone does not close prematurely.

Q: In addition to revising the round closing rules are there any changes to the rules governing the calculation and publication of the amount of excess supply remaining at the end of an auction round?

A: Yes, there are changes to the rules concerning excess supply at the system level and for export-constrained zones. At the system level, the published excess supply value will be based on the supply quantity used to evaluate whether to close the Rest-of-Pool Capacity Zone. In effect, this tells capacity suppliers the maximum amount of supply that will potentially be competing for Capacity Supply Obligation awards in the next round at the system level.

For export-constrained zones, the revised excess supply rule is also based on the revised round closing conditions for export-constrained zones. Again, the revised rule tells capacity suppliers the maximum amount of supply that will still be competing in the next round in the export-constrained zone.

The ISO does not publish information about the excess supply in import-constrained capacity zones during the course of the descending clock auction. Thus, there are no rule changes related to the calculation and publication of excess supply in import-constrained capacity zones.

XI. CONCLUSION

Q: Does this conclude your testimony?

A: Yes.

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

Executed on April 15, 2016.

Christopher Geissler, Economist

Matthew White, Chief Economist

Attachment 1: Performance of Zonal Demand Curves

Demand Curve Design Improvements (1 of 3) — System-Level Results

Zonal Configuration: SENE (import) and Rest Of System	Reliability Results						Total Market Payments		
	System LOLE (events/yr)	System 1-day-in	Avg. System Cleared Capacity (MW)	Cleared Capacity Std. Dev (MW)	Freq. Below 1-in-5 (% of draws)	Freq. Below NICR (% of draws)	Average ($mil/yr)	Average of Bottom 20% ($mil/yr)	Average of Top 20% ($mil/yr)
(A) Zones and Est. Net CONE at FCA10 Values									
Forward-Looking (Full PFP-based) Supply Models									
Model 1 (Base Case): All Capacity Bids/Offers at Est. Net CONE	0.100	10.0	34,151	-	-	-	$4,430	-	-
Model 2 (Sensitivity Cases): Marginal Offer Priced Above/Below Net CONE									
(2a) Marginal Offer at $ 7.00 / kw-mo.	0.070	14.3	34,721	-	-	-	$2,917	-	-
(2b) Marginal Offer at $ 9.55 / kw-mo.	0.090	11.1	34,316	-	-	-	$3,933	-	-
(2c) Marginal Offer at $12.00 / kw-mo.	0.110	9.1	34,011	-	-	-	$4,898	-	-
(2d) Marginal Offer in Import Zone 10% Above Est. Net CONE	0.109	9.2	34,151	-	-	-	$4,559	-	-
Historic (FCA7/8/9-based) Supply Model									
Model 3: Historic Supply-based Simulated Bidding	0.077	13.0	34,600	283	0.0%	4.4%	$3,259	$2,368	$4,283
(B) Additional Sensitivity Cases: Alternative Net CONE Values									
Model 4: All Capacity Bids/Offers at Alternative Hypothetical Net CONE Values:									
(4a) If Est. Net CONE is revised to 20% below FCA10 Value	0.100	10.0	34,151	-	-	-	$3,544	-	-
(4b) If Est. Net CONE is revised to 20% above FCA10 Value	0.100	10.0	34,151	-	-	-	$5,316	-	-
Model 5: Different Zonal Est. Net CONE Values Scenario									
(5a) Import Zone Est. Net CONE revised to 20% above FCA10 Value	0.100	10.0	34,393	-	-	-	$4,716	-	-
(C) Stepped Supply Model									
Model 6a (Modest Slope)	0.102	9.8	34,127	76	0.0%	37.2%	$4,516	$4,306	$4,925
Model 6b (Steep Slope)	0.103	9.7	34,114	120	0.0%	36.3%	$4,571	$4,269	$5,238
Model 6c (Steeper Slope, More Entry and Exit)	0.106	9.4	34,078	168	0.0%	45.5%	$4,703	$4,118	$5,682

Demand Curve Design Improvements (2 of 3) — SENE Results

Zonal Configuration: SENE (import) and Rest Of System	Reliability Results					SENE Clearing Price			
	System LOLE (events/yr)	Constraint's Contribution to LOLE (events/yr)	Avg. SENE Cleared Capacity (MW)	Cleared Capacity Std. Dev (MW)	Freq. Below LSR (% of draws)	Average ($/kW-m)	Clearing Price Std. Dev ($/kW-m)	Frequency at Cap (% of draws)	Frequency of Price Separation (% of draws)
(A) Zones and Est. Net CONE at FCA10 Values									
Forward-Looking (Full PFP-based) Supply Models									
Model 1 (Base Case): All Capacity Bids/Offers at Est. Net CONE	0.100	0.000	10,880	-	-	$10.81	-	-	-
Model 2 (Sensitivity Cases): Marginal Offer Priced Above/Below Net CONE									
(2a) Marginal Offer at $ 7.00 / kw-mo.	0.070	0.000	10,880	-	-	$7.00	-	-	-
(2b) Marginal Offer at $ 9.55 / kw-mo.	0.090	0.000	10,880	-	-	$9.55	-	-	-
(2c) Marginal Offer at $12.00 / kw-mo.	0.110	0.000	10,880	-	-	$12.00	-	-	-
(2d) Marginal Offer in Import Zone 10% Above Est. Net CONE	0.109	0.009	9,946	-	-	$11.89	-	-	-
Historic (FCA7/8/9-based) Supply Model									
Model 3: Historic Supply-based Simulated Bidding	0.077	0.000	11,054	463	0.6%	$7.90	$1.81	0.0%	36.4%
(B) Additional Sensitivity Cases: Alternative Net CONE Values									
Model 4: All Capacity Bids/Offers at Alternative Hypothetical Net CONE Values:									
(4a) If Est. Net CONE is revised to 20% below FCA10 Value	0.100	0.000	10,880	-	-	$8.65	-	-	-
(4b) If Est. Net CONE is revised to 20% above FCA10 Value	0.100	0.000	10,880	-	-	$12.97	-	-	-
Model 5: Different Zonal Est. Net CONE Values Scenario									
(5a) Import Zone Est. Net CONE revised to 20% above FCA10 Value	0.100	0.014	9,815	-	-	$12.97	-	-	-
(C) Stepped Supply Model									
Model 6a (Modest Slope)	0.102	0.000	10,809	163	0.0%	$11.05	$0.65	0.0%	81.7%
Model 6b (Steep Slope)	0.103	0.000	10,810	151	0.0%	$11.19	$1.10	0.0%	86.4%
Model 6c (Steeper Slope, More Entry and Exit)	0.106	0.000	10,802	245	0.1%	$11.54	$1.54	0.5%	69.1%

Demand Curve Design Improvements (3 of 3) — Rest-of-System Results

Zonal Configuration: SENE (import) and Rest Of System	Reliability Results					ROS Clearing Price		
	System LOLE *(events/yr)*	System 1-day-in	Avg. ROS Cleared Capacity *(MW)*	Cleared Capacity Std. Dev *(MW)*	Freq. Below 1-in-5 *(% of draws)*	Average *($/kW-m)*	Clearing Price Std. Dev *($/kW-m)*	Frequency at Cap *(% of draws)*
(A) Zones and Est. Net CONE at FCA10 Values								
Forward-Looking (Full PFP-based) Supply Models								
Model 1 (Base Case): All Capacity Bids/Offers at Est. Net CONE	0.100	10.0	23,271	-	-	$10.81	-	-
Model 2 (Sensitivity Cases): Marginal Offer Priced Above/Below Net CONE								
(2a) Marginal Offer at $ 7.00 / kw-mo.	0.070	14.3	23,841	-	-	$7.00	-	-
(2b) Marginal Offer at $ 9.55 / kw-mo.	0.090	11.1	23,436	-	-	$9.55	-	-
(2c) Marginal Offer at $12.00 / kw-mo.	0.110	9.1	23,131	-	-	$12.00	-	-
(2d) Marginal Offer in Import Zone 10% Above Est. Net CONE	0.109	9.2	24,205	-	-	$10.81	-	-
Historic (FCA7/8/9-based) Supply Model								
Model 3: Historic Supply-based Simulated Bidding	0.077	13.0	23,547	418	0.0%	$7.85	$1.77	0.0%
(B) Additional Sensitivity Cases: Alternative Net CONE Values								
Model 4: All Capacity Bids/Offers at Alternative Hypothetical Net CONE Values:								
(4a) If Est. Net CONE is revised to 20% below FCA10 Value	0.100	10.0	23,271	-	-	$8.65	-	-
(4b) If Est. Net CONE is revised to 20% above FCA10 Value	0.100	10.0	23,271	-	-	$12.97	-	-
Model 5: Different Zonal Est. Net CONE Values Scenario								
(5a) Import Zone Est. Net CONE revised to 20% above FCA10 Value	0.100	10.0	24,579	-	-	$10.81	-	-
(C) Stepped Supply Model								
Model 6a (Modest Slope)	0.102	9.8	23,318	176	0.0%	$11.02	$0.64	0.0%
Model 6b (Steep Slope)	0.103	9.7	23,303	187	0.0%	$11.16	$1.09	0.0%
Model 6c (Steeper Slope, More Entry and Exit)	0.106	9.4	23,277	246	0.0%	$11.49	$1.52	0.4%

memo

To: NEPOOL Markets Committee

From: Market Development and Business Architecture & Technology

Date: December 7, 2015

Subject: FCM Zonal Demand Curve Methodology – *Revised Edition*

This memorandum discusses the ISO's proposed method for developing capacity demand curves for the annual Forward Capacity Auctions (FCA). Building on a set of broad design principles, it describes a practical method for specifying capacity demand curves that can be readily applied to both the current and potentially different future capacity zone configurations. The proposed method is built on a clear engineering-economic foundation, and is designed to procure capacity cost-effectively relative to other potential demand curves.

This revised edition incorporates and supersedes the contents of the memorandum on this topic provided to the Markets Committee on November 3rd, 2015. This revision adds a detailed discussion of demand curves for export-constrained capacity zones, and provides an expanded explanation of cost-effective capacity procurement between zones.

Importantly, this analysis indicates that modifications to the existing system demand curve are desirable in conjunction with the zonal demand curves. We explain these modifications to the system curve in detail, and discuss some of the problems that arise without these modifications. In essence, the system-level and zonal demand curves should be developed in an integrated manner, since they jointly determine how much capacity clears in each portion of the system.

The proposed method will also enable the FCA to incorporate certain improvements to the clearing process between zones. Under prior zonal design proposals, if an import-constrained zone cleared at a higher price than the system, the aggregate capacity cleared would fall short of the system's sloped demand curve. In contrast, the new method will enable the rest-of-system zone to clear on the system-level demand curve if an import or an export zone clears on a zonal demand curve at a different price than the rest-of-system. This memorandum also explains these clearing process improvements, and how they are enabled by the proposed demand curve design.

The ISO anticipates discussing this subject with stakeholders over the next several months. We welcome additional questions and feedback on these issues.

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Design Principles

In some respects, demand curves for capacity serve a purpose similar to demand curves for other goods and services. They characterize how much more consumers will buy when the price is low, and how much less they will buy when the price is high. The practical question before us is: At different prices, how much more or less should be purchased in the capacity market?

The ISO's proposed answer to this question starts with several design principles. These principles are:

1. *Reliability*. The demand curves should be expected to procure sufficient capacity, both in the system and in any modeled capacity zone, to enable the ISO to meet its reliability planning obligations. In practice, this is assessed on the basis of meeting the '1-in-10' loss of load expectation (LOLE) reliability standard, on average (over time).

2. *Sustainability*. The capacity market's clearing prices should remunerate investment in capacity at a level sufficient to attract new entry when needed. This means that the capacity market's equilibrium needs to exhibit prices that average at least the (true) net cost of new entry; otherwise, the FCA would not clear sufficient supply to meet the reliability objective (Principle 1).

3. *Cost-Effectiveness.* Whenever clearing prices differ among capacity zones, the zonal demand curves should be designed to minimize the bid-cost of procuring capacity overall. That is, capacity purchases should be allocated across zones cost-effectively, given each auction's prices, while meeting the overall reliability and sustainability objectives (Principles 1 and 2).

In addition to these three design principles, there are other benefits of using sloped demand curves in the FCA. One is that, relative to procuring fixed quantities, sloped demand curves tend to reduce volatility in auction clearing prices over time. That implies less year-over-year variation in revenues (for capacity suppliers) and expenditures (for capacity buyers). A second benefit is that sloped demand curves can significantly attenuate the incentive for a participant to exercise market power in the FCA. This is because sloped demand curves reduce the effect on the market clearing price if a seller raises (or, in the buyer-side case, a buyer lowers) a resource's bid price in the FCA.

An important further consideration is design 'robustness' to alternative zone configurations. One of the ISO's practical objectives is capacity demand curve rules that will work – in the sense of satisfying the design principles and benefits noted above – even if the FCA is conducted using a different zonal configuration at some point in the future. A cavalier set of curves may seem appealing for one zonal configuration, but if the underlying methodology is not designed carefully so as to handle alternatives, it may leave little confidence that it will work in future years.

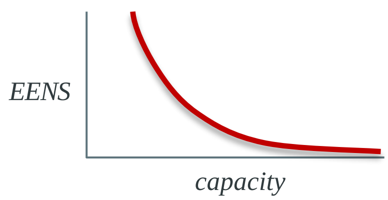
In developing an improved method for determining demand curves to be used in each FCA, the ISO has not elevated some of these principles or benefits above the others. Rather, we emphasize the three enumerated design principles in the analysis that follows because they have precise interpretations that are a valuable guide for developing demand curves for the FCA. The balance of this memo explains how.

Economic Foundations

The FCA can be viewed as making trade-off between two basic considerations. At a high-level, the benefit of procuring more capacity is that it reduces energy demand that may go unserved (sometimes called 'lost load'). However, procuring more capacity is costly. Capacity demand curves can be viewed as a means to make an economic choice about how this tradeoff between the costs and benefits of procuring more or less capacity should be resolved.

■ **Capacity Avoids Lost Load.** To evaluate the potential lost load that should be expected with a given level of installed capacity, the ISO's reliability planning models calculate a performance metric known as the 'expected energy not served' (EENS).[1] EENS is measured in MWh per year, and depends on (among other things) the amount of capacity installed on the system and in each constrained zone.

EENS is an informative measure of how frequently an incremental unit of capacity should be needed to avoid lost load. Graphically, the relationship between EENS and capacity looks like this:



Intuitively, when the system has low levels of capacity, procuring an incremental MW of capacity tends to have a big reliability benefit because it reduces lost load in many hours per year. At the opposite extreme, when the system has high levels of capacity, an incremental MW of capacity generally has little reliability benefit: it is rarely needed and reduces lost load in very few (if any) hours per year.

The ISO's approach to developing capacity demand curves is based, in part, on how expected lost load – more specifically, EENS – is impacted by procuring different capacity levels (zonally and system-wide). To explain this approach, we first explain how to interpret the FCA as a cost-minimization problem using EENS, rather than using a 'fixed' capacity requirement.

■ **The FCA as a Cost-Minimization Problem.** At a conceptual level, the capacity auction's design can be thought of as a cost-minimization problem. Until FCA 8, it sought to minimize the costs of procuring capacity, subject to a fixed quantity requirement. Without a fixed quantity requirement (FCA 9 and subsequently), the FCA instead makes a tradeoff – albeit implicitly – between the cost of procuring capacity and an implied 'benefit' of each additional MW procured. To justify a particular set of demand curves, it is insightful to view the FCA as a minimization problem in this new context, and to be more explicit about what is the incremental 'benefit' of each MW procured.

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[1] Also known as 'expected unserved energy' (EUE). We use the two term synonymously.

In an FCA without a fixed capacity requirement, one can conceptualize the FCA's clearing objective as a cost minimization problem that minimizes both the total bid-based costs of capacity procured and the total 'cost' of the expected energy not served. To explain this more precisely, a formula will help. Let *i* represent a resource, and b_i denote its bid price (or offer price) in the FCA. Further, let q_i represent the quantity (i.e., the CSO MW) that resource *i* is awarded the FCA. (Thus, if a resource is not awarded a CSO at all, its value of q_i is zero.) Minimizing the total bid-cost of capacity and the total 'cost' of EENS can be expressed succinctly as:

$$\text{minimize}_{\{q_i\}} \quad \underbrace{\textstyle\sum_i b_i \cdot q_i}_{\substack{\textit{Cost of} \\ \textit{capacity (as-bid)}}} \; + \underbrace{PF \cdot EENS(Q_{SYS})}_{\substack{\textit{Cost of} \\ \textit{lost load}}} \qquad (1)$$

In this expression, the first term (the summation) is the total bid-cost for all CSO MW's awarded. The second term can be interpreted as the total cost associated with the expected energy not served when total cleared capacity is Q_{SYS}. Note that—for the moment—we've assumed in this formulation an unconstrained system with no capacity zones. (We extend this to capacity zones further below).

Conceptually, this minimization problem can be viewed as a 'penalty factor' model, in which an incremental 'cost' (the penalty factor) of *PF* is assigned to each MWh of expected energy not served. Unlike having a fixed capacity requirement, an auction built on this foundation will minimize the total bid-costs of capacity (the first term) and expressly account for the additional reduction in unserved energy from procuring incremental capacity. In general, market designs based on penalty-factor models such as (1) are a familiar, practical means to send market price signals and procure supply cost-effectively when there is both a cost to acquire a good (in this case, capacity) and a cost associated with some form of shortage or unmet demand.[2]

To be clear, the expression in (1) serves a conceptual purpose – is it not how the FCA's market clearing engine currently works, nor a complete mathematical representation of how the ISO proposes to clear the FCA in the future. Nonetheless, this conceptually simple cost-minimization idea conveys some important economic points for how capacity demand curves should be developed for the FCA.

■ **From Penalty Factors to Demand Curves**. In order for the FCA to be cost-effective, it must procure capacity so that the marginal cost of another unit of capacity is equal to the marginal reliability benefit that capacity provides. That is, the FCA should clear a level of capacity such that

$$\textit{Marginal Capacity Cost} = \textit{Marginal Reliability Benefit} \qquad (2)$$

Although the reliability benefits of capacity can have many dimensions, we will focus on its benefit in the form of reducing expected energy not served (the resource adequacy problem). In that context, applying this cost-benefit principle using insights from the penalty-factor model in (1) provides a

[2] For example, the ISO's market model for real-time energy and reserves achieves its cost-minimization objective using a closely-related penalty factor model. The principle difference from (1) is that the real-time reserve pricing model uses a fixed reserve requirement, instead of a smoothly-decreasing $EENS(Q_{SYS})$ function. As seen shortly, using $EENS(Q_{SYS})$ yields a demand curve that declines smoothly with additional supply.

reasonable economic framework for developing capacity demand curves. To see how, we'll next examine both sides of the expression in (2), and then connect these concepts to the supply and demand curves used to clear the FCA.

On the left-hand side of (2), the marginal capacity cost is determined by the bid-price submitted by the marginal (that is, price-setting) capacity supply resource in the FCA. Nothing new there, and nothing about the development of capacity demand curves should change the interpretation of capacity supply curves. In a capacity auction for an unconstrained system (*i.e.*, without any zones), the marginal capacity cost at each level of capacity is simply the aggregate supply curve in the FCA.

On the right-hand side of (2), the reliability benefit of procuring capacity arises from reducing the total cost of lost load. That has two components. The first is the impact on expected energy not served of another unit of capacity. We will refer to this as the *marginal reliability impact* (MRI) of capacity. Stated mathematically, for an unconstrained system without capacity zones:

$$\textit{Marginal Reliability Impact} = \frac{d}{dQ_{SYS}} EENS(Q_{SYS}) \qquad (3)$$

The second component is the incremental 'cost' (the penalty factor) assigned to each MWh of expected energy not served. Stated more precisely, the cost-minimization model for the FCA in expression (1) corresponds to the following marginal reliability benefit:

$$\textit{Marginal Reliability Benefit} = -PF \times \textit{Marginal Reliability Impact} \qquad (4)$$

In words, the marginal reliability benefit is determined by the reliability impact of procuring another increment of capacity that reduces expected energy not served (in MWh per year), evaluated at (*i.e.*, multiplied by) an incremental 'cost' of *PF* assigned to lost load (in \$ per MWh).[3]

You can see where this is headed. Conceptually, if demand curves for capacity are specified on the basis of its marginal reliability benefit, using the formula in expression (4), then running the FCA will procure a level of capacity that satisfies the familiar benefit-cost logic in expression (2). This occurs because the capacity auction's market mechanism clears at the point where the capacity supply curve intersects the capacity demand curve. That is, the FCA will procure capacity where its marginal capacity cost equals its marginal reliability benefit.[4]

Practicalities

The ISO's proposed approach to developing sloped capacity demand curves is based on the simple logic that the cost of capacity should be reasonably commensurate with its marginal reliability benefit. As will be shown presently, this economic foundation can be readily used to build zonal demand curves.

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[3] The negative sign in expression (4) keeps the marginal reliability benefit positive. This is because the marginal reliability impact in (3) is negative: Additional capacity reduces expected energy not served.

[4] We simplify, though the point is general. In practice, capacity supply bids/offers can be 'lumpy' (non-rationable) and, in certain situations, this may result in these marginal conditions holding approximately rather than exactly. That does not undermine the logic for specifying demand curves as described here, however.

As a practical matter, applying the logic in expressions (3) and (4) to obtain capacity demand curves requires a reasonable basis for determining the penalty factor, and a practical process for evaluating the marginal reliability impact of procuring additional capacity. We touch on each of these two issues next, and provide additional detail in subsequent sections.

■ **Deriving a Penalty Factor.** How should a penalty factor on lost load be interpreted, and how should it be determined? Broadly answered, a high value of *PF* means that the region is willing to pay a great deal to avoid unserved energy demand, and the FCA should tend to procure a great deal of capacity to minimize this possibility. A low value of *PF* would result in the FCA procuring less capacity, though how much less will depend on the offer prices of capacity suppliers.

As a general matter, the ISO does not propose to assume a specific value for consumers' incremental 'cost' of expected energy not served; this is empirically difficult to ascertain with any confidence. Rather, the ISO proposes to *derive* (not assume) a value for the penalty factor *PF* that is (just) high enough to simultaneously satisfy the Reliability and the Sustainability design principles described at the outset of this paper. In that way, the penalty price will be set at the level just necessary to produce outcomes consistent with the reliability planning standards, on average and over time, and to induce new entry when necessary. We present a simple method to do this in detail further below.

It is worth noting that *any* capacity demand curve necessarily has – at least implicitly – *some* value assigned to the incremental 'cost' of lost load. In past design efforts, this value was implicitly determined by the curve's location and slope.[5] In contrast, the ISO's revised approach explicitly acknowledges this parameter, and the role it plays in affecting capacity demand curves. That is, instead of leaving the incremental 'cost' of lost load as an unstated parameter, this approach adopts a (derived) value calculated to procure capacity levels consistent with the region's reliability planning requirements, on average and over time.

■ **Evaluating the Marginal Reliability Impact.** Although the marginal reliability impact formula in expression (3) may seem complex or novel, it is neither. It has a simple interpretation as the change in expected energy not served with respect to capacity procured. This is a smoothly increasing curve. Indeed, the ISO's existing reliability planning models are able to produce the EENS curve and its gradient (the MRI) presently, both for an unconstrained system and with the capacity zones modeled in the FCA. These curves are obtained using the system parameters and inputs that are currently used

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[5] An example may help. Using round numbers: Suppose that at NICR a (hypothetical) system demand curve specifies a price of \$120,000 / MW-year (*i.e.*, \$10 per kw-month). Suppose further that the marginal reliability impact of another increment of capacity at NICR is a 6 hours per year. The implied penalty factor this demand curve assigns to lost load at NICR is \$120,000 / 6 = \$20,000 per MWh annually. Stated in other words, since this (hypothetical) demand curve does not procure another increment of capacity (beyond NICR) when additional capacity is offered at a price of \$120,000 per MW-year and the next increment would reduce EENS by 6 hours per year, the demand curve implicitly assigns an incremental 'cost' of avoiding lost load, at the margin, of \$20,000 per MWh annually. Note that, as a technical matter, the implicit penalty factor on EENS may not be constant for all capacity levels under some demand curves (it is constant under the ISO's method).

to calculate various ICR-related values for each auction, and that are vetted annually with stakeholders.[6]

■ **Implications.** There are three main implications of this analysis for demand curves:

1. There is an engineering-economic foundation for developing FCA demand curves based on the marginal reliability impact of capacity. Doing so will enable the FCA, by clearing the auction where capacity supply meets capacity demand, to procure capacity levels that seek to balance the cost of capacity and the cost of avoiding lost load.

2. A reasonable basis for assessing the marginal reliability benefit of capacity is the product of two terms: (a) The impact of incremental capacity purchases on EENS, which the ISO's existing reliability planning models can calculate, and (b) a penalty rate for each MWh of EENS. As explained further below, an appropriate value for the penalty rate can be derived using the Reliability and Sustainability central design principles.

3. This economic foundation is not specific to capacity zones, but also applies to the demand for capacity at the system level. That implies modifications to the existing system demand curve may be needed, in order to ensure the system curve and zonal curves work together properly.

In sum, the marginal reliability benefit function in (3) is the basis for how the ISO proposes to determine capacity demand curves for the FCA. Before discussing some additional properties of these curves, it is useful to first explain how to extend this framework for a constrained system with capacity zones. This we address next.

Demand Curve for an Import Capacity Zone

The previous section presented the engineering-economic foundations for capacity demand curves, and for simplicity used formulas applicable to an unconstrained system without capacity zones. In this section, we explain how to extend this framework to derive zonal demand curves for an import-constrained capacity zone.

■ **EENS In a System With Zones.** As noted previously, the expected energy not served depends on both the total capacity in the system, and the amount of capacity located in any constrained zones. The precise way zonal constraints affect EENS is important to the derivation of zonal demand curves, so we step through that first.

Conceptually, the demand for capacity in an import zone – above and beyond the demand for capacity at the system level – should be based on the *additional* EENS in the system that arises due to the existence of a zonal import limit. For simplicity, assume there are two capacity zones in the system:

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[6] These inputs are summarized in ISO's annual *ICR Related Values Report*, available at http://www.iso-ne.com/system-planning/resource-planning/installed-capacity-requirements. Preliminary values are presented and discussed with stakeholders at the PSPC during the year preceding each auction; for FCA10, updated ICR related values are available in the August 2015 PSPC Meeting materials at http://www.iso-ne.com/committees/reliability/power-supply-planning.

An import-constrained zone ('ICZ'), and the rest-of-system ('ROS') zone. In general, the total EENS in the system can be decomposed into the sum of two components: (1) The EENS in an *unconstrained* system (*i.e.*, without any zones) with aggregate capacity level Q_{SYS}, and (2) the *additional* EENS due to the zonal import limit, when the capacity level in the import-constrained zone is Q_{ICZ}. Stated as a formula,

$$\underbrace{EENS(Q_{ICZ}, Q_{SYS})}_{\substack{\textit{Total} \\ \textit{EENS}}} = \underbrace{EENS_{SYS}(Q_{SYS})}_{\substack{\textit{Unconstrained} \\ \textit{System EENS}}} + \underbrace{EENS_A(Q_{ICZ}, Q_{SYS})}_{\substack{\textit{Additional EENS due to} \\ \textit{Zonal Import Limit}}} \qquad (5)$$

The left-hand side of this equation is the total expected energy not served in this constrained system when there is Q_{ICZ} capacity in the import-zone, and Q_{SYS} capacity in the system. On the right-hand side, the first term is the EENS system-wide if, counter to fact, there was no zonal import limit constraint and the system has Q_{SYS} capacity. (Since this term is not dependent on Q_{ICZ}, we use the notation $EENS_{SYS}$ for this term in (5) to indicate it is a different mathematical function).

The second term on the right-hand side of (5) has an important and different interpretation. Mathematically, this term represents the *additional* EENS in this two-zone constrained system, above and beyond the EENS that would occur in an unconstrained system with the same total capacity Q_{SYS}, if there is only Q_{ICZ} capacity in the import zone. (We use the subscript 'A' in the last term in (5) to indicate this is the additional EENS due to the import limit, as distinct from both the total EENS and the unconstrained system $EENS_{SYS}$.)

■ **Marginal Reliability Impacts.** As before, we will derive the capacity demand curve based, in part, on the marginal reliability impact of capacity in the zone. For zones, however, the marginal reliability impact of capacity is a more subtle concept than it is for the system as a whole. This is because there are two different ways to measure of the marginal reliability impact of capacity in an import zone:

1. *Marginal Reliability Impact of Capacity Substitution.* This is the reduction in total EENS if 1 MW of capacity is substituted (or shifted) out of the ROS zone and into the ICZ, holding total system capacity constant.

2. *Marginal Reliability Impact of Capacity Additions.* This is the reduction in total EENS if 1 MW of capacity is added in the ICZ, and the ROS zone capacity is held constant (so total system capacity also increases by 1 MW).

In principle, a demand curve can be derived for a capacity zone based on either of these two marginal reliability impact measures. But they are different things. We use the former, because both the FCA's clearing algorithm and the interpretation of the zonal demand curves are simplified using the former instead of the latter. In particular, by using the first measure of zonal marginal reliability impacts, the zonal demand curves (under the proposed method) will properly calculate *congestion prices* between capacity zones.

■ **Evaluating Zonal Marginal Reliability Impacts.** At this point, a few additional elements will lead us to a simple way to interpret (and evaluate) zonal capacity demand curves. First, to obtain the zonal capacity demand curve, we determine the marginal reliability impact of capacity substitution. This equals the gradient of the 'additional EENS' function in equation (5). Specifically, if there is Q_{ICZ} capacity currently in the ICZ, then the marginal reliability impact of substituting one unit of capacity out of the ROS zone and into the ICZ (*i.e.*, while holding total system capacity constant at Q_{SYS}) is the partial derivative:

$$\frac{\partial}{\partial Q_{ICZ}} EENS_A(Q_{ICZ}, Q_{SYS})\Big|_{Q_{SYS}} \qquad (6)$$

This looks complicated, but stay with it for just another moment – there's something important just around the curve (so to speak). Although this is a measure of the marginal reliability impact, it isn't practical (in this form) for a demand curve – the expression in (6) is a function of two variables, Q_{ICZ} and Q_{SYS}. To get a zonal demand curve that is a function of one variable, Q_{ICZ}, we can evaluate this marginal reliability impact when the system's capacity is at the equilibrium level consistent with the Reliability principle (*viz.*, the '1-in-10' capacity level in an unconstrained system). That is, we can evaluate the zonal marginal reliability impact of capacity substitution as:[7]

$$\textit{Zonal Marginal Reliability Impact} = \frac{\partial}{\partial Q_{ICZ}} EENS_A(Q_{ICZ}, Q_{SYS})\Big|_{Q_{SYS}=1:10} \qquad (7)$$

This is a negative, smoothly increasing function of the amount of capacity in the import zone. That means substituting additional capacity into an import zone reduces EENS, but has a progressively a diminishing marginal impact.

Importantly, the ISO's reliability planning models can calculate all of the relevant zonal EENS values, and their derivatives, presently. For an import zone, this is a two-step process: First, the unconstrained system EENS (and 1-in-10 capacity level) are determined using the existing reliability planning model assuming no import constrained zones, which yields the first term in (5). Second, the same model is run after imposing the zonal import limits to obtain the second term in (5), and its gradient in (7). Neither of these calculations involves any additional information beyond that presently used to calculate the various ICR-related values for each FCA.

■ **Demand Curve for an Import Zone.** The demand curve for an import capacity zone is given by its marginal reliability benefit function, in a manner consistent with the engineering-economic foundations described earlier. Using the notation P_{ICZ} to denote the price specified by the import zone demand curve at Q_{ICZ} capacity, we have:

$$\textit{Zonal Demand:} \qquad P_{ICZ}(Q_{ICZ}) = -PF \times \textit{Zonal Marginal Reliability Impact}$$

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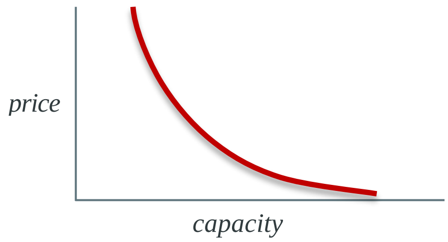
[7] Using Q_{SYS} at the 1:10 (NICR) level in (7), as opposed to a different level, is not crucial; the marginal reliability impact curve may not vary materially for different levels of Q_{SYS} over the empirically-relevant range of system capacity levels.

A demand curve for an import capacity zone will have this general shape:



This curve's shape is intuitive: It decreases with additional capacity, and gets progressively flatter as more capacity is added. The reason for this shape is simple: When there is relatively little capacity in a zone, there are many expected hours with lost load (in the zone), and any further reduction in capacity has a large, adverse marginal reliability impact. In other words, when there is relatively little capacity, the curve must rise steeply as capacity falls. In contrast, when there is ample capacity, there are few expected hours with lost load (in the zone), and any additional capacity in the zone may be rarely used. Thus, at higher capacity levels in the zone, the marginal reliability impact does not change much with additional capacity so the curve declines gradually.

In sum, to respect these fundamental (physical) properties of how capacity affects expected energy not served, the demand curves must have the 'scooped' shape shown in the figure above.

■ **Zonal Demand Curves Specify Congestion Prices.** The zonal demand curve derived above has a very important interpretation.   Because it is based on the *additional* EENS that occurs due to the zonal import limit, the prices specified by the zonal demand curve represent the *additional* amount that should be paid for capacity in the zone – that is, in addition to the system capacity clearing price. In other words, the zonal demand curve is a *congestion pricing* curve.

An analogy may help. Recall the basic interpretation of congestion prices in the energy market, which arise whenever a constraint limits the amount of energy that can be imported into a particular location. Ignoring energy losses (which are not relevant here), the locational and the system prices differ by the congestion price across the constraint:

Locational Marginal Price = System Energy Price + Locational Congestion Price

An import-zone capacity demand curve, as derived above, works on the same logic:

Zonal Capacity Price = System Capacity Price + Zonal Congestion Price

Consider the following example. Suppose the system demand curve clears at a price of $6 per kw-month.   Imagine that, at the quantity of capacity cleared in the import zone, the zonal demand curve specifies a price of $2 per kw-month. This $2 price is not the total price paid to capacity in the zone; it is the *congestion price* for capacity in the zone. The total price paid to capacity in the zone is given by the system's capacity clearing price of $6 *plus* the zonal congestion price of $2, or $8 per kw-month in total.

Continuing the example, imagine that a particular capacity resource offers into the market at $7 per kw-month. If it is located in the import capacity zone, it would clear and be paid the zonal clearing price of $8 per kw-month. If another resource also offers $7 per kw-month and is located in the ROS zone, it would not clear the auction (because its offer price exceeds the system capacity clearing price of $6 per kw-month).

■ **Pricing Congestion with a Zonal Capacity Demand Curve Makes Sense.** It is natural wonder why interpreting the zonal demand curve in terms of congestion pricing make economic sense. This is a consequence of how the import-zone capacity demand curve is being evaluated. Specifically, the zonal marginal reliability impact (in expression (7)) is the change in EENS if we *substitute* (or shift) one unit of capacity out of the ROS zone and into the ICZ. Substituting capacity from the ROS zone into an ICZ has a reliability benefit, in general, because it helps reduce EENS inside the zone when the zonal import constraint is binding and incremental capacity in the ROS would not.

In other words, a zonal demand curve based on the marginal reliability impact of capacity substitution tells us how much more 1 MW of additional capacity is worth if procured in the ICZ, *instead of* being procured in the ROS zone. That is, it indicates what the price *difference* should be between the ICZ and the ROS zone. This price difference across a constrained interface is, of course, what we normally call the congestion price.

■ **Import Limits and LSR.** It is important to note that no-where in the derivation of the zonal capacity demand curve is the current Local Sourcing Requirement imposed as a 'fixed' requirement. The zonal demand curve does account, in the design directly, for the import interface transfer limit into the zone. This is because the marginal reliability impact of zonal capacity is derived from the *additional* EENS due to the zonal interface import limit (*viz.*, the last term in expression (5)). With additional import transfer capability, the zonal demand curve becomes flatter; and if there was no import interface limit at all, the last term in (5) would be zero and the zonal demand curve would be a flat line at zero. Put differently, a constraint that never binds always has a congestion price of zero.

■ **Marginal Reliability Benefit of Capacity Additions.** It is useful to connect a few more dots between the system and zonal prices. As just explained, the price specified by the zonal capacity demand curve is the zone's capacity congestion price, because it is based on the reliability impact of *substituting* capacity between the ICZ and the ROS zone. Let's now answer: What is the marginal reliability benefit of adding capacity inside the import-constrained zone, if the MW is a net addition to the system (rather than being substituted between zones)?

The answer is the *sum* of the system price and the zonal congestion price. In other words, the total price to be paid to capacity in an import constrained zones is the system price plus the zonal congestion price, like congestion pricing normally works.

To see how this holds in this context, one can think of our net capacity addition inside the ICZ in two conceptual steps: A reliability benefit from adding another MW of capacity into the ROS zone, *plus* an additional potential reliability benefit from shifting that MW out of the ROS and into the ICZ. The marginal reliability benefit of the first step is given by the system demand curve (as explained in the prior section on economic foundations), and yields the system capacity clearing price. The marginal reliability benefit of the second step, substituting the new MW from the ROS into the ICZ, is given by the zonal capacity demand curve that specifies the zonal congestion price. The total effect of adding an incremental MW of capacity inside the import-constrained zone, if it is a net addition to the system, is therefore the sum of the two prices. In other words, paying all capacity inside the import-constrained zone the system clearing price *plus* the zonal demand curve's congestion price will, in fact, compensate capacity investment inside the ICZ commensurate with its marginal reliability benefit.

Demand Curve for an Export Capacity Zone

An important feature of this engineering-economic approach to developing capacity demand curves is that also provides a logical basis for defining demand curves for an export-constrained capacity zone. The approach is analogous to that for import zones, with various signs reversed. We step through the analysis here.

■ **EENS With Export Zones.** As with an import zone, the demand for capacity in an export zone – above and beyond the demand for capacity at the system level – is based on the *additional* EENS in the system that arises due to the existence of a zonal export limit. Here, the additional EENS will generally be positive – that is, the export limit *increases* the expected energy not served.

Assume now there are three capacity zones in the system: An import-constrained zone (ICZ), an export-constrained zone (ECZ) and the rest-of-system (ROS) zone. The total EENS in the system can be decomposed into the sum of three components: (1) The EENS in an unconstrained system (*i.e.*, without any zones), (2) the additional EENS due to the import zone transfer limit, and (3) the additional EENS due to the export zonal transfer limit. Stated as a formula,

$$\underbrace{EENS(Q_{ICZ}, Q_{ECZ}, Q_{SYS})}_{\substack{\textit{Total} \\ \textit{EENS}}} = \underbrace{EENS_{SYS}(Q_{SYS})}_{\substack{\textit{Unconstrained} \\ \textit{System EENS}}} + \underbrace{EENS_{AI}(Q_{ICZ}, Q_{SYS})}_{\substack{\textit{Additional EENS due to} \\ \textit{Zonal Import Limit}}} + \underbrace{EENS_{AE}(Q_{ECZ}, Q_{SYS})}_{\substack{\textit{Additional EENS due to} \\ \textit{Zonal Export Limit}}} \qquad (8)$$

The left-hand side of this equation is the total expected energy not served in this constrained system when there is Q_{ICZ} capacity in the import zone, Q_{ECZ} capacity in the export zone, and Q_{SYS} capacity in the system. On the right-hand side, the first two terms are the same as discussed previously for an import zone (see equation (5) *ff.*). The new, final term is the additional EENS in this three-zone constrained system if there is Q_{ECZ} capacity in the import zone. Note the last two terms do not depend on the other constrained zone's capacity directly, because the additional EENS in an export zone is not impacted by the import-zone limit, and vice versa. (We use subscripts '*AI*' and '*AE*' in the two last terms in (8) to indicate these additional EENS functions are distinct from one another, and from the unconstrained system $EENS_{SYS}$.)

■ **Evaluating Zonal Marginal Reliability Impacts.** Proceeding similarly to the case with an import zone, we evaluate an export zone's marginal reliability impact as the change in the 'additional' EENS function applicable to the export zone (*i.e.*, the gradient of the last term in expression (8)):

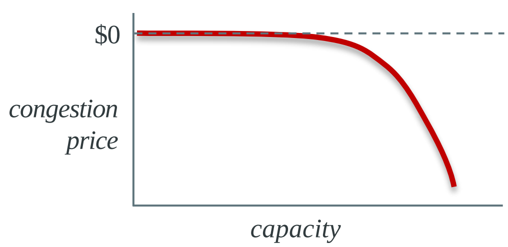
$$Zonal\ Marginal\ Reliability\ Impact = \frac{\partial}{\partial Q_{ECZ}} EENS_{AE}(Q_{ECZ}, Q_{SYS})\Big|_{Q_{SYS}=1:10} \quad (9)$$

As with an import zone, this is the marginal reliability impact of capacity substitution from the ROS zone into the ECZ. This is a positive, smoothly increasing function of the amount of capacity in the export zone. That means, after a certain level, substituting additional capacity into an export zone *increases* overall EENS, and has a progressively greater marginal reliability impact.

■ **Demand Curve for an Export Zone.** The demand curve for an export capacity zone is given by its marginal reliability benefit. Using the notation P_{ECZ} to denote the price specified by the export zone demand curve at Q_{ECZ} capacity, the demand curve is determined by the same formula as for an import zone:

$$Zonal\ Demand: \quad P_{ECZ}(Q_{ECZ}) = -PF \times Zonal\ Marginal\ Reliability\ Impact$$

As with an import zone, this demand curve represents a congestion price. With an export zone, however, this price is always negative or zero; that is, resources in an export-constrained zone are paid the same, or less than, resources in the rest-of-system. Graphically, the demand curve for an export capacity zone will have this general shape:



This curve's shape is intuitive: It decreases with additional capacity. When there is relatively little capacity in a zone, the export transmission limit rarely (or never) binds, so the marginal reliability impact of capacity substitution into the zone is negligible and the curve is flat. However, when there is a high level of capacity in the export zone, there are many expected hours when the export limit is binding and additional capacity in the export zone may be rarely used. Thus, at higher capacity levels in the export zone, substituting more capacity from the ROS into the ECZ ('behind' the constraint) has a progressively adverse marginal reliability impact. The curve therefore begins to fall steeply at higher levels of capacity in an export zone.

■ **Export Zone Demand Curves Specify Congestion Prices.** Since the zonal demand curve derived above is a *congestion pricing* curve, it does not directly determine the total price paid to resources in the zone. Rather, as with other zones, they are paid based on the sum of the system price and the zonal congestion price:

$$Zonal\ Capacity\ Price = System\ Capacity\ Price + Zonal\ Congestion\ Price$$

An example may help. Suppose the system demand curve clears at a price of $6 per kw-month. Imagine that, at the quantity of capacity cleared in the export zone, the export zone demand curve specifies a congestion price of $ –2 per kw-month. The total price paid to capacity in the zone is given by the system's capacity clearing price of $6 plus the zonal congestion price of $–2, or $4 per kw-month in total.

Continuing the example, imagine that a particular capacity resource offers into the market at $5 per kw-month. If it is located in the export capacity zone, it would not clear since its offer exceeds the zonal capacity clearing price of $4. If another resource also offers $5 per kw-month and is located in the ROS zone, it would clear the auction because its offer price is less than the system capacity clearing price of $6 per kw-month.

Importantly, since capacity supply offers/bids are non-negative, an export zone's congestion price cannot be so large (in magnitude) as to produce a negative zonal capacity clearing price paid to capacity providers. That is, if the system clearing price is $6 per kw-month as before, the most negative hypothetical congestion price that could occur across the export zone interface would be $–6 per kw-month. As a result, the lowest possible total price paid to capacity a zone is zero.

■ **Interpreting the Export Demand Curve.** As with an import zone, an export zone demand curve is based on the marginal reliability impact of capacity substitution. It tells us how much less 1 MW of additional capacity is worth if procured in the ECZ, *instead of* being procured in the ROS zone. That is, it indicates what the price *difference* should be between the ECZ and the ROS zone. Export-zone congestion prices are negative (or zero) because incremental capacity in the ECZ is an imperfect substitute for capacity in the ROS: incremental capacity in the ROS helps reduce EENS in the ROS when the zonal export constraint is binding, but incremental capacity in the ECZ would not.

■ **Export Limits and MCL.** It is important to note that no-where in the derivation of the zonal capacity demand curve is the current Maximum Capacity Limit rating imposed as a 'fixed' limit. The export zonal demand curve does account, in the design directly, for the export interface transfer limit out of the zone. This is because the marginal reliability impact of zonal capacity is derived from the *additional* EENS due to the zonal interface export limit (*viz.*, the last term in expression (8)).

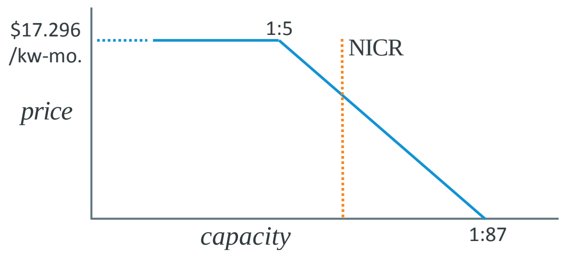
With additional export transfer capability, the export zonal demand curve becomes flatter; and if there was no export interface limit at all, the last term in (8) would be zero and the zonal demand curve would be a flat line at zero. As with any transfer limit, a constraint that never binds always has a congestion price of zero.

■ **Practical Implications.** There's one caveat to this simple and intuitive economic logic of demand curves and congestion pricing. Its foundations also imply that the *system* demand curve, and therefore the system capacity clearing price, should also be determined on the basis of the marginal reliability benefit analysis. In other words, the system and zonal demand curves should be viewed as an integrated system for procuring capacity, and designed cognizant of one another (*viz.*, on the basis of (8)); if they are not, the curves may procure too much capacity in one zone and too little in another (relative to the actual marginal reliability impact in each zone). This brings us to why certain modifications to the system sloped demand curve are desirable, and that we will discuss presently.

Concerns with the Existing System Demand Curve

Based on its marginal reliability analyses for capacity demand curves, the ISO recommends the region make certain modifications to the system-level capacity demand curve, in addition to adopting zonal curves. In this section, we summarize the main concerns we have identified with the existing demand curve. We explain the specific proposed modification to address these concerns in the subsequent section.

Presently, the FCA uses a linear system-level demand curve. Graphically, it looks like this:



As a preliminary observation, this linear demand function resulted from a general consensus among stakeholders and the ISO that it represents an improvement upon the prior practice (in FCA 8 and prior auctions) of using a fixed requirement, or vertical capacity demand curve, at NICR. Indeed, the existing sloped system demand curve is a considerable improvement in that respect.

With the benefit of additional time and analysis since the current system demand curve was adopted, we have identified three concerns with this linear system demand curve.

■ **Current system curve poorly reflects capacity's marginal reliability impact.** The existing system curve does not account for the fact that, from a reliability perspective, the change in the marginal reliability impact with an additional unit of capacity is very different when the system is much *below* NICR than when it is *above* NICR.

When system capacity is below NICR, the change in the marginal reliability impact if the FCA clears one less increment of capacity is quite high. At capacity levels approaching the 1-in-5 reliability level (*i.e.*, LOLE = .2, or 33,076 MW for FCA10), the ISO's reliability planning models indicate the EENS exceeds 1600 MWh per year and increases rapidly as capacity levels decline further. The system demand curve should therefore rise more steeply – to ensure the FCA clears closer to NICR – as capacity levels fall below NICR.

In contrast, when the system capacity is well above NICR, the change in the marginal reliability impact with each increment of capacity is quite low. For example, at the 1-in-50 capacity level (*i.e.*, LOLE = .02, or approximately 36,400 MW), the EENS is approximately 60 MWh annually and decreases very gradually, and at a progressively slower rate, with additional capacity. In other words, to reflect the marginal reliability impact properly, the system demand curve should become steadily 'flatter' as it decreases.

Viewed in terms of marginal reliability impacts more directly, the ISO's reliability planning models indicate that the change in the system's marginal reliability impact with another increment of capacity is approximately 10 times as large at the 1-in-5 capacity level as it is at the 1-in-50 level. This means the system demand curve should have approximately *10 times the slope* at 1-in-5 as it does at 1-in-50, if it is to properly reflect how incremental capacity affects reliability. The existing linear demand curve, which has the *same* slope at both 1-in-5 and 1-in-50, was not selected with this pertinent information at hand. As a result, it poorly reflects how reliability changes when capacity levels differ from the 1-in-10 level.

There are economic consequences to this mismatch between the marginal reliability impacts of capacity investment and the prices resources would be paid (as specified by the demand curves). Specifically, the existing linear demand curve may tend to undercompensate resources for the reliability benefits they provide – and send too low a price signal for new investment – when the system is significantly below NICR, because the demand curve should be steeper in this region than it is today. The existing linear demand curve will also tend to overcompensate resources for the reliability benefits they provide – and send too high a price signal for new investment – over a broad range of capacity levels whenever the system is above NICR, because the demand curve should be much lower, and much flatter, in that region than it is today.

■ **Current system curve procures more capacity than necessary to meet the reliability objective (Principle 1).** The second concern relates to where the system curve is positioned relative to the intersection of NICR and Net CONE. With the benefit of additional analysis that was not available at the time the linear system demand curve was selected, it appears the existing system curve will tend to procure more capacity than necessary to meet the 1-in-10 (LOLE = 0.1) objective, on average over time.

This concern is primarily a consequence of the fact that the system demand curve should be convex, on the basis of engineering-economic considerations discussed previously. With a convex demand curve, the same average reliability level (*i.e.*, LOLE = .1) can be achieved with a lower average capacity and lower average cost.

A simple (hypothetical) example may help. Assume the FCA clears each year at either Net CONE minus $2 per kw-month, Net CONE, or Net CONE plus $2 per kw-month, with all three outcomes equally likely. If a system demand curve has the same slope as the current linear system demand curve, then to achieve an average LOLE of 0.1 over time (using current New England system parameters) in this simple example requires capacity levels of 34,662 MW, 34,203 MW, and 33,743 MW at each price (respectively). The capacity procured is 34,203 MW on average (over time).

Now imagine we use a convex demand curve. This enables different quantities to be cleared at each price while achieving the same average LOLE. Specifically, if a convex demand curve procures the capacity levels of 34,418 MW, 34,151, and 33,925 MW at each price (respectively), the average LOLE is still 0.1 (using current New England system parameters). The average capacity procured would be lower, however at 34,165 MW. Because the average capacity procured is lower, average total costs are also lower: In this (hypothetical) example, average capacity costs are $1.5 million less with the convex curve than with the linear curve, while achieving the same average reliability.

This phenomenon isn't terribly intuitive, but it is important. It occurs because LOLE is a (highly) non-linear, convex function of capacity. Using a convex demand curve is much better able to match thus fundamentally non-linear relationship, enabling the FCA to achieve the 1-in-10 target *on average* with a lower level of installed capacity on average.

The inefficiencies that arise using a linear demand curve in this fundamentally non-linear setting are the reason that, when the current linear system demand curve was developed, it was necessary to 'tune' the linear curve so it passes considerably to the 'right' of NICR at the Net Cone value. With a convex curve, it is not necessary for the demand curve to pass similarly far to the 'right' of NICR at Net Cone, resulting in lower average capacity procurement – and a lower average total cost of capacity – to deliver the same average reliability. While the difference in total cost in this intentionally-simplified example are modest (*i.e.*, only $1.5 million), with other supply offers and larger potential variation in clearing prices over time, the efficiency consequences may be considerably larger.

The broad point is there are pure efficiency gains to be realized when a curve's shape reflects sound engineering-economic fundamentals. The region can achieve same reliability target on average, at a lower average cost to society, by modifying the existing system curve to reflect these fundamentals using the MRI information now available.

■ **Current system curve does not cost-effectively allocate capacity procurement across capacity zones.** The third concern relates to the allocation of capacity purchases across zones. When zonal demand curves are employed, rather than fixed zonal requirements, the same system overall reliability can often be maintained by procuring a little more capacity in one zone, and a little less capacity in another (but not at a 1-for-1 rate, in general). It is therefore necessary to have a principle to decide how much to demand in each zone when there are multiple choices that achieve the same overall reliability level.

In this context, it becomes important to select system and zonal demand curves that are *cost-effective.* In simple terms, this means that when there are multiple choices regarding how much capacity to demand in each zone (including the Rest-of-System zone) that would achieve the same overall reliability, the quantities to be chosen should minimize the total bid-cost of capacity overall.

The ISO's concern here is that, based on the additional analysis now available, the existing system demand curve does not satisfy this basic cost-effectiveness design principle. Specifically, when prices separate, there is generally a different level of system capacity than that specified by the existing system demand curve that would achieve (a) the same or better system reliability (b) at lower total bid-cost.

This cost-effectiveness principle between zones was not considered when the existing system demand curve was developed, in part because the existing system demand curve was developed in isolation of zonal demand curve considerations. The system demand curve and the zonal demand curves should not be considered in isolation, however, as they jointly determine – in combination with the capacity supply bids/offers – how much capacity will is cleared in each zone (including the Rest-of-System capacity zone).

The concept and logic of cost-effective demand curves when there are both system-level and zonal demand curves is addressed in detail presently. There we explain why the status quo is not cost-effective, and why cost-effectiveness requires the system and zonal curves to be developed as an integrated process. Before addressing cost-effectiveness in greater detail, however, it will be useful to summarize the relevant modifications the ISO recommends to the system-level demand curve.

System Demand Curve Modifications

To address all of the foregoing concerns with the existing system demand curve, the ISO proposes to modify it in conjunction with the adoption of zonal demand curves. This section summarizes the proposed system demand curve modifications.

The ISO's proposed modifications to the system demand curve are based on the same foundations discussed earlier in this memorandum (see pages 3-5). Using the notation P_{SYS} to denote the price specified by the system demand curve at Q_{SYS} capacity, the modified system demand curve would be determined as:

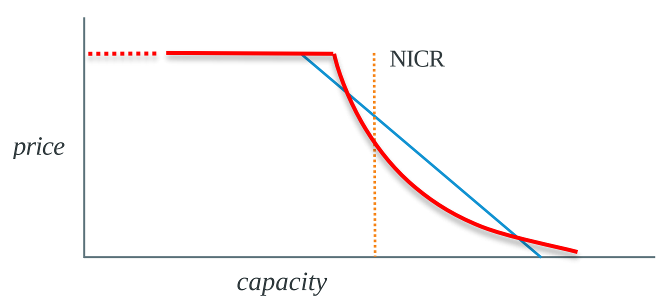
$$\textit{System Demand:} \qquad P_{SYS}(Q_{SYS}) = -\,PF \times \textit{Marginal Reliability Impact}$$

Here, the marginal reliability impact is determined by the change in EENS in an unconstrained system with respect to system capacity (*see* expression (3) on page 5):

$$\textit{Marginal Reliability Impact} = \frac{d}{dQ_{SYS}} EENS_{SYS}(Q_{SYS})$$

Note that the system-level MRI of capacity is always calculated in the same way, regardless of the number and types of capacity zones in the system. This ensures that the assessment of the marginal reliability impact of adding system capacity is robust to the zonal configuration.[8]

Since a picture is worth a thousand words, we expect the appropriately-modified system demand curve should look generally like this. The new (red) curve has the 'scooped', or convex, shape and the existing (blue) curve is the downward sloping straight line:



[8] Mechanically, this can be verified by noting that the system-level MRI of capacity is the same whether calculated using the first-term on the right hand side of expression (5) (on page 8, in the case with only import zones), or if calculated using expression (8) (on page 12, in the case with both import and export constrained zones). In each case, and consistent with the current process for determining the NICR, the system-level demand curve and system-level MRI is determined for an unconstrained system.

The flat section of both curves is the existing price cap (the FCA Starting Price), which we do not propose to modify. As with any capacity demand curve that reflects the marginal reliability impact of capacity, this modified system curve gets progressively flatter with additional capacity, reflecting the rapidly diminishing marginal reliability benefit of additional capacity over the relevant range of possible system capacity levels.

Although the existing system demand curve was developed in isolation of any specific zonal demand curve design, it is important to note that the system curve affects the allocation of capacity purchases among zones – in particular, both the system and the zonal curves determine demand in the ROS zone. This brings us back to the topic of cost-effective procurement between capacity zones, next.

Cost-Effectiveness Between Capacity Zones

One of the central design principles guiding the ISO's proposal is to procure capacity cost-effectively among zones. In this section, we explain this principle and illustrate it using simple examples. We then explain why the ISO's proposed method achieves this principle, and why other alternative zonal demand approaches (including the status quo) do not.

■ **Concepts.** First, some clarifying terminology will be useful. We say a (set of) demand curves is *cost-effective* if, for each possible clearing price in each zone, there is no way to modify the cleared capacity levels among zones that achieves (a) the same or better system reliability at (b) lower total bid-cost. Stated in other terms, if a set of demand curves is <u>not</u> cost effective, then different demand curves would deliver the same reliability at lower total bid-costs.

By itself, cost-effectiveness would seem a difficult principle to argue with. In essence, it asks that any set of zonal demand curves pass a basic test: Can we alter the quantities demanded at the given prices, by potentially purchasing a little more in one zone and a little less in another, in a way that maintains the same overall system reliability but lowers total auction bid-cost? If so, then the demand curve values at those prices could be modified, with no loss in reliability, to lower cost.

Importantly, cost-effectiveness between zones is not assured by satisfying the reliability and sustainability design principles alone (Principles 1 and 2). Those principles apply to the average revenue and average system reliability achieved by the design (over time). Cost effectiveness is a much stronger principle. It asks that at *any* set of clearing prices that could occur in a given auction, the demand curves should specify quantities to purchase in each zone that minimize total bid-cost for the particular level of reliability achieved in that year's auction (which could be higher or lower than '1-in-10' in a given year).

Cost-effectiveness between zones is easiest to understand with the help of a few examples, which we provide next.

■ **Example.** To explain these ideas, we first consider a simple example. This example explains how to check whether a set of demand levels for a system with two capacity zones is cost effective or not. It also explains why.

First, assume a system with two zones: One export-constrained zone, and the ROS zone. In this hypothetical example, we assume the system clears at $9 per kw-month, and the quantity given by the system at this demand curve is 34,000 MW. We assume the ECZ clears lower, at $6 per kw-month, and at that price the quantity given by the ECZ demand curve is 9,500 MW. These values are collected in the table below:

Example 1a.	System	ECZ	Ratio	*Interpretation*
Total Price	$9	$6	**1.5**	*More costly in System*
Demand (MW)	34,000	9,500		
Total MRI (h/yr)	– 2/3	– 1/3	**2.0**	*More effective in System*

Now, to assess the reliability impacts of capacity in each zone, we require their marginal reliability impact values. Here, as shown in the table above, we assume that the MRI of additional capacity in the system is – 2/3 MWh; that means one incremental MW of capacity in the system would reduce the system's total EENS by 2/3 MWh per year. However, capacity in the ECZ is not as effective, with an MRI of capacity additions of only – 1/3 MWh.[9] The MRI of capacity additions in an ECZ is less than (or, in some cases, equal to) the MRI in the system, because a unit capacity in ROS can help avoid lost load in the ROS when the export interface limit is binding, but a unit of capacity in the ECZ cannot.

The most important part of the table above is the ratios column. They reveal that, at the margin:

- Additional capacity is 50% more costly in the ROS than in the ECZ ($9 v. $6);
- Additional capacity is *twice* as effective in the ROS than in the ECZ (– 2/3 v. – 1/3).

This implies the demand curves that generated these quantities are *not* cost effective. They demand too much capacity in the ECZ relative to the ROS. Reducing demand in the ECZ and increasing it in the ROS – at the right rates – can deliver the same reliability at lower total cost.

To see this, let's consider what happens if we procure 1 MW *less* capacity in the ECZ. First, note the impact of one less MW of capacity in the ECZ on EENS: – 1 MW × (– 1/3 MRI) = + 1/3 MWh increase in EENS. If we procure a little *more* capacity in the ROS, however, we can offset this reliability impact. Crucially, we do not need to buy quite as much capacity in the ROS, because it is more effective there. Specifically, if we demand an additional .5 MW of capacity in the ROS, the impact of this higher procurement on EENS is + .5 MW × (– 2/3 MRI) = – 1/3 MWh.

[9] In Example 1a, we list the MRI of capacity *additions* in each zone. An underlying assumption is that the MRI of capacity *substitution* from the ROS into the ECZ is +1/3 MWh/yr (an export zone's MRI of substitution is always positive). In general, the MRI of capacity additions in any zone is equal to the system MRI plus the MRI of capacity substitution. Applied in this example, the MRI of capacity additions in the ECZ is – 2/3 MWh/yr + 1/3 MWh/yr = – 1/3 MWh/yr, as shown in the table.

Put this in more general terms, incremental capacity in the ROS and in the ECZ are *partial substitutes*. Both help improve reliability, but not equally so. Buying just a little more of the one that is more effective (*i.e.*, has the higher absolute MRI), and much less of the one that is less effective, can achieve the same overall level of reliability.

Now, back to cost. Let's collect our numbers for the modified demands in a new table, below. In the first row, we indicate the change we are checking to test the cost-effectiveness of the original demand curves: Buying 1 MW less in the ECZ, and .5 MW more in the ROS. The second row shows the change in EENS due to each demand change. And the third row shows the change in cost.

Example 1b.	**ROS**	**ECZ**	**Total**	***Interpretation***
Δ Capacity	+ .5 MW	– 1 MW	**– .5 MW**	*Less total capacity*
Δ EENS (MWh)	– 1/3	+ 1/3	**0**	*Same reliability*
Δ Cost ($/mo)	+ $4,500	– $6,000	**– $1,500**	*Lower total cost*

By demanding 1 MW less in the ECZ at a price of $6/kw-month, cost falls by $6,000 per month. Demanding .5 MW more in the ROS raises cost, but not by as much: .5 MW × $9 / kw-mo. × 1000 = $4,500 per month. In sum, the results in the table above show that the original demand curves in this example are not cost effective: Demanding different quantities can achieve the same overall reliability, at a lower total cost.

Stepping back a bit, this simple example illustrates a core issue for demand curve design with capacity zones. When zonal demand curves are employed, rather than fixed zonal requirements, the same overall reliability can often be achieved by procuring a little more capacity in one zone and a little less capacity in another (but not at a 1-for-1 rate, as this example illustrates). It is therefore necessary to decide how much to demand in each zone, since there are multiple choices that achieve the same overall reliability level. The ISO's proposed design principle to resolve this decision is the cost-effectiveness criterion. This means that when there are multiple choices regarding how much capacity to demand in each zone (including the Rest-of-System zone) that would achieve the same overall reliability, the quantities demanded should minimize the total bid-cost of capacity overall.

■ **Status Quo is Not a Cost Effective Solution.** One of the ISO's concerns is that, based on the additional insights and MRI information now available, the FCA's status quo – with the current system demand curve and fixed zonal requirements – is not cost-effective.

Here's a simple way to see this, extending the prior example. Here we use actual quantities specified by the current linear system demand curve, and a (non-hypothetical) export-constrained zone corresponding to the Northern New England (NNE) export zone tested for FCA10. The indicative maximum capacity limit for the NNE zone is 8,830 MW.[10]

[10] See the ISO's November 16, 2015 presentation at http://www.iso-ne.com/static-assets/documents/2015/11/a2_fcm_zonal_development_3_review_of_determinations_for_fca_10.pdf

Assume as before that the clearing prices in the system and NNE export zone are \$9 and \$6, respectively (this analysis can be performed similarly with any other prices). The quantities specified at these prices by the current system demand curve and by a 'vertical' zonal demand curve at the NNE maximum capacity limit are shown below. Using the ISO's marginal reliability analysis results (for FCA 10 inputs), we have calculated the total MRI of capacity additions in each zone at these two capacity levels.[11] These are provided in the following table:

Example 2a.	**System**	**ECZ**	**Ratio**	***Interpretation***
Total Price	\$9	\$6	**1.5**	*More costly in System*
Demand (MW)	34,983	8,830		
Total MRI (h/yr)	– .312	– .233	**1.34**	*Relatively less effective*

The ratio column in this table indicate that, at these prices, capacity is 50% more costly in the ROS than in the ECZ (\$9 v. \$6), but capacity is only 34% more effective in the ROS than in the ECZ, at the margin. This implies the quantities procured at these prices are *not* cost effective. Since the price ratio exceeds the effectiveness ratio, these quantities procure too much capacity in the ROS relative to the ECZ. (Note this is the opposite situation from Example 1, where there was too much capacity in the ECZ relative to the ROS).

Reducing demand in the ROS and increasing it in the ECZ – at the right rates – can deliver the same reliability at lower total cost. To see this, consider procuring 1 MW more capacity in the ECZ, and procuring .75 MW (= 1/1.34) less in the ROS. The change in capacity levels, EENS, and cost is summarized in the following table:

Example 2b.	**ROS**	**ECZ**	**Total**	***Interpretation***
Δ Capacity	– .75 MW	+ 1 MW	**– .25 MW**	*Less total capacity*
Δ EENS (MWh)	+ .233	– .233	**0**	*Same reliability*
Δ Total Cost (\$/mo)	– \$6,750	+ \$6,000	**– \$750**	*Lower total cost*

In sum, there is a net efficiency gain from procuring different quantities than specified under the status quo, at least at these prices. Although we omit it here, similar analyses using other prices yield the same general finding: The status quo was not designed to procure capacity levels in different zones cost-effectively. Modifying the demand curves with this objective as a design principle has a clear and simple benefit – at any price levels, it can achieve the same reliability at lower total cost.

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[11] At these capacity levels, the system MRI = –.312 MWh/yr and the NNE MRI of capacity substitution is +.079 MWh/yr, so the total MRI of capacity additions in the NNE zone is –.312 + .079 = –.233 MWh/yr, as shown in the table. For the underlying data, see http://www.iso-ne.com/static-assets/documents/2015/12/a09_iso_indicative_demand_curve_values_fca10_zones_12_03_15.xlsx .

■ **Procuring Capacity Cost-Effectively: Example.** By design, the ISO's proposed method for specifying demand curves (both for the system and each zone) solves this problem and procures capacity cost-effectively. We show this first with another example, which illustrates a general result. We then use the example to explain why the ISO's proposed method works generally, and why other demand curves approaches would not be cost effective.

Consider again the same two zones, the ROS and the export-constrained zone corresponding to the Northern New England (NNE) zone tested for FCA10. Building on the prior examples, assume the same prices as before (the same conclusion would hold at any other prices, for reasons explained further below). However, now consider the quantities demanded under the NNE zonal demand curve and the modified system demand curve under the ISO's proposal. These quantities, along with the corresponding MRI values, are shown in the table below.[12]

Example 3a.	**System**	**ECZ**	**Ratio**	***Interpretation***
Total Price	$9	$6	**1.5**	*More costly in System*
Demand (MW)	34,390	9,000		
Total MRI (h/yr)	– .498	– .334	**1.5**	*Same relative effectiveness*

The ratio column in this table indicates that, at these prices, capacity is 50% more costly in the ROS than in the ECZ ($9 v. $6), and simultaneously capacity is 50% more effective in the ROS than in the ECZ, at the margin. As in the previous examples, one could again consider procuring 1 MW more in the ECZ, and 2/3 MW (= 1/1.5) less in the ROS, which will again hold reliability (total EENS) unchanged. But in contrast to the previous examples, there would be no efficiency gain in doing so, as there is no further cost saving to be had by substituting incremental capacity between the zones.

Put simply, at the quantities demanded under the ISO's proposed method, there is no way to procure different capacity levels that, given clearing prices, achieves the same reliability at lower cost. That is, the ISO's approach allocates capacity purchases among the zones (including the ROS zone) cost-effectively.

■ **How ISO's Design Solves the Cost-Effectiveness Problem.** At a conceptual level, one might think that finding the cost-effective quantities at all possible clearing prices is a tedious process: For each set of possible prices (at least, whenever zones price separate), the possible quantities to demand in each zone need to be checked for cost-effectiveness, then modified until the right ratios are determined. Fortunately, there is instead a simple and general formula for determining the cost-effective quantities.

[12] For a graphical version of the ISO's proposed system and NNE demand curves using FCA10 inputs, see the ISO's December 10, 2015 Markets Committee presentation at http://www.iso-ne.com/static-assets/documents/2015/12/a09_iso_presentation_12_10_15.pptx. At the capacity levels in Example 3a, the system MRI = –.498 MWh/yr and the NNE MRI of capacity substitution is +.164 MWh/yr, so the total MRI of capacity additions in the NNE zone is –.498 + .164 = –.334 MWh/yr, as shown in the table. For the underlying demand curve and MRI data, see *op cit.*

The ISO's integrated set of zonal and system-level demand curves is built on a key insight: In order for capacity to be procured cost-effectively, the *relative* prices in any two capacity zones must equal their relative marginal reliability impacts. This is the same observation illustrated by the two ratios in the last Example 3a, above. In terms of formulas, this condition can be expressed as:

$$\frac{P_Z^{total}(Q_Z)}{P_{SYS}(Q_{SYS})} = \frac{MRIA_Z(Q_Z)}{MRI_{SYS}(Q_{SYS})} \qquad (10)$$

In this formula, the zonal price on the top-left is the zone's clearing price (*i.e.,* the sum of the system price and the zonal congestion price). The zonal MRI on the top-right is for capacity additions (*i.e.*, MRIA is the sum of the system MRI and the zonal MRI of capacity substitution). This formula is simply another way to express the ratios that we compared in Examples 1, 2, and 3 above: If the price ratio diverges from the MRI ratios, as in Examples 1 and 2, then the quantities demanded (at those prices) are not cost-effective – as we discovered directly. In Example 3, the price ratio equals the MRI ratio, and the quantities demanded are cost-effective.

Generalizing this observation, to be cost-effective a set of demand curves must be selected to satisfy equation (10). This might seem like a complex thing to do, but it is actually quite simple: It means the demand curves must be equal to the applicable MRI, times a constant. That's it. Why, you ask? In that way, the constants will cancel when the demand curves are used to determine prices (on the left-hand side of the price ratio above), and the cost-effectiveness condition – *by construction* – always holds. Stated more explicitly, the ISO's proposed demand curves for the system and the zones are cost-effective precisely because they are defined proportionately to the appropriate MRI:

$$P_{SYS}\,(Q_{SYS}) \;=\; Constant \times MRI_{SYS}(Q_{SYS})$$

And, for each zone,

$$Zonal\ Congestion\ Price(Q_Z) \;=\; Constant \times Zonal\ MRI(Q_Z)$$

where the *Zonal MRI* is for capacity substitution, so that $MRIA_Z(Q_Z) = Zonal\ MRI(Q_Z) + MRI_{SYS}(Q_{SYS})$. That is, plugging these formulas for the clearing prices into the left-hand side of equation (10) will result in the demand curves' constant canceling out in the ratios. That means the cost-effectiveness property holds at *all* prices, using the ISO's proposed demand curve formulas.

■ **Practical Implications.** Three key points are worth noting here. First, this analysis helps explain the ISO's concern with retaining the existing linear system demand curve. Achieving cost-effectiveness requires an integrated set of demand curves for each zone and the system (as the latter determines the ROS zone procurement). The existing linear demand curve does not satisfy the essential conditions that yield cost-effective procurement, and cannot be 'made to fit' these conditions.

At one level, this should not be surprising. The existing system demand curve was developed in isolation of any zonal demand curve considerations, at a time before the marginal reliability impact analyses the ISO has now conducted were available. Given the information now available, however, it is difficult to countenance continuing with a linear demand curve for which, at any prices, a different set of system and zonal demand curves would yield the same reliability at lower cost.

Second, cost-effectiveness matters in practice. For instance, with cost-effective demand curves, the FCA sends the right price signals for investment: They signal that investors should be willing to incur (say) 20% higher costs to build capacity in the ICZ (relative to the ROS) if, and only if, doing so will reduce total EENS by (at least) 20% more than building in the ROS. That is, the price signals will attract capacity in the more expensive zone when adding capacity there has a commensurately higher reliability benefit, and will not if it does not provide benefit commensurate to its higher cost.

Third, the cost-effectiveness condition explained in this section holds for the ISO's proposed demand curves at *all* prices, not just at Net CONE. For that reason, cost-effectiveness is a highly proscriptive condition on demand curve design: Cost-effectiveness admits only one class of demand curves, those which satisfy the ratio in (10). The only 'degree of freedom' in demand curve design, when cost effectiveness is a principle of the demand curve design, is the choice of the constant term in the demand curves.

This brings us to the remaining step of the ISO's demand curve methodology, which is the choice of the constant term in each demand curve. This constant corresponds to the penalty factor discussed earlier in this note, and its value is determined using the two other core design principles: Reliability and Sustainability (Principles 1 and 2). We explain the details of this final step next.

Applying the Reliability and Sustainability Principles

Although the general shape of the proposed capacity demand curves is determined by the marginal reliability impact functions (for the system and each zone, respectively), they also depend, in part, on the constant (the penalty factor) in each demand curve. Here, we explain how the ISO proposes to derive this parameter.

■ **Graphical Interpretation as a Scaling Factor.** The penalty factor described earlier in this memorandum can be thought of as a demand 'scaling' factor. Graphically, it simply 'stretches' the demand curves vertically. That is, if this scaling factor is increased by 10%, then the height (the prices) of the demand curve will increase by 10% at each quantity level; if the scaling factor doubles, the height of the demand curve at each quantity will double; and so forth.

The impact of three different demand scaling (penalty) factor values on a hypothetical system demand curve are illustrated on the next page (this figure omits the price cap, which is unaffected by the penalty factor). In an unconstrained system without capacity zones, the determination of the appropriate penalty factor value has a simple graphical interpretation: The penalty factor *PF* is set where the demand curve yields Net Cone at a capacity equal to NICR.

If the demand scaling factor is set too high, then the demand curves will procure more capacity than the reliability standards require, or set clearing prices above Net Cone, or both. At the opposite extreme, if the demand scaling factor is set too low, it will fail to remunerate investment at a level sufficient to meet the ISO's reliability planning obligations.[13]

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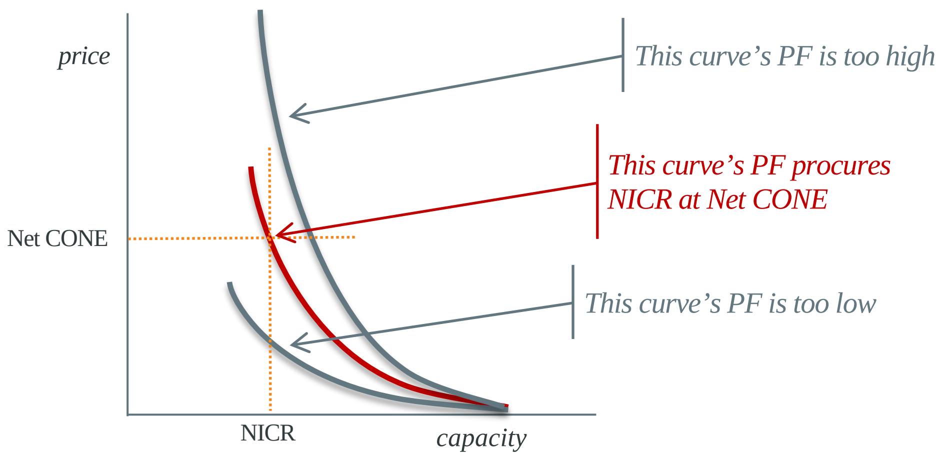
[13] In determining the scaling (penalty) factor, the ISO uses the LOLE $\leq$ .1 reliability standard as proscribed in its existing reliability planning standards; it is not using a specific EENS value *per se* as the reliability requirement.



■ Competitive Equilibrium and the Penalty (Demand Scaling) Factor. Importantly, the penalty factor *PF* is not an *assumed* value. Rather, it is part of the demand curves and derived in a manner to satisfy the central design principles of reliability and sustainability. Specifically, the ISO proposes to set this demand scaling factor at the (smallest) value such that the demand curves for the system, and for each import-constrained zone, will satisfy these principles simultaneously.

These two principles are assessed by whether, at a price of Net Cone (in each zone), the demand curves yield sufficient capacity to ensure the annual Loss of Load Expectation (LOLE) is less than 0.1 for the system (respecting all zonal interface limits). In setting the penalty factor in this manner, we are making explicit use of the capacity market's long-run equilibrium property that the marginal capacity supply offer, whether existing or new, is offered at Net Cone. This long-run equilibrium is a property of the ISO's two-settlement capacity market design (also known as Pay for Performance), once the new design is completely phased in with its full Performance Payment Rate (starting with FCA15). This equilibrium bidding model is more consistent with the economics of competitive capacity supply pricing under the two-settlement capacity market than the historical bidding behavior of capacity suppliers, which was generally governed by their so-called 'going forward' (or avoidable) capital costs.

In addition, the assumption of Net Cone as the equilibrium capacity price is also consistent with the cash-flow and pricing assumptions actually employed in the ISO's discounted cash-flow models used to estimate Net Cone. In this way, the proposed method to set the demand curves' penalty (scaling) factor is internally consistent with both the current two-settlement capacity market design, as well as the Net Cone models with which the demand curves are calibrated.

■ General Case with Equilibrium Price Separation. In the general case, determining the scaling factor may involve an additional step beyond simply finding the point where the modified system demand curve intersects NICR and Net Cone. The additional step arises if there are different estimated Net Cone values in different capacity zones. In this case, the (single) scaling factor must be determined so that each zone's curve will clear, on average over time, at (at least) the zone's Net Cone value.

In practice, this involves two straightforward steps. First, we use the ISO's reliability planning model to compute the marginal reliability impact functions for each import constrained zone and for the system. Second, we determine the *smallest* value of the penalty factor such that, with the resulting system of demand curves, the system's overall LOLE $\leq .1$, when evaluated accounting for all zonal import limits, at the quantities cleared under each zonal and system demand curve at Net Cone in each zone.

This means, in practice, that if there is a higher estimated ("administrative") Net Cone value for an import zone than the estimated Net Cone value applicable to the ROS zone, the scaling factor may be larger than would be obtained for an unconstrained system without capacity zones. In either case, however, the logic remains the same: The scaling factor is set just high enough – but no higher – than necessary to meet the 1-in-10 LOLE reliability criterion and remunerate capacity investment at Net Cone.

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ISO new england

memo

To: NEPOOL Markets Committee

From: Jeff McDonald
Vice President, Market Monitoring

Date: January 11, 2016

Subject: Zonal Demand Curves and Administrative Pricing

Summary

The ISO and IMM discussed continuation of administrative pricing under sloped zonal demand curves at NEPOOL Markets Committee meetings in the Winter of 2015. There was concern at that time that there was sufficient opportunity for market power to exist and be exercised in the Forward Capacity Market, especially by new capacity which is not currently subject to offer review and mitigation. The current proposal for sloped zonal demand curves, along with the market rules filed by the ISO regarding resource retirement, contain provisions that improve competition and reduce concerns regarding the exercise of market power. The ISO is aware of and considering additional provisions that may also improve the degree of competition in the capacity market. At this time, I am not proposing that the ISO implement administrative pricing along with the sloped zonal demand curves. While there are several factors identified above that are proposed or could be pursued by the ISO that would improve competition, my position rests heavily on the characteristics of the existing proposal, FERC approval of the ISO's filing on retirement reform, and the ISO maintaining larger capacity zones.

Market Power Concerns

It is important that there is sufficient competition in the Forward Capacity Market to insure that participants offer competitively allowing the auction to produce competitive outcomes. In a single-price auction, the potential market damage associated with uncompetitive outcomes can be significant. The discussion of the continuation of administrative pricing with sloped zonal demand curves in early 2015 was motivated by two concerns.

Without sufficient competition to discipline offers, it is possible that new entry could exercise market power and artificially inflate the auction clearing price.[1] Lack of competition could allow new entry to offer at a price above their competitive offer (risk-adjusted net cone). This is most likely to occur in a smaller capacity zone or when there has been an unanticipated shock to the supply / demand balance. Sufficient information exists that suppliers of new capacity can infer when existing supply is relatively short and they are facing little or no competition. There are mitigation mechanisms in place for existing resources and import offers, however current market rules do not provide for mitigation of new internal capacity for seller-side market power.

The second concern is that it may be advantageous to incumbent suppliers to hold existing brown-field sites out of the development cycle to restrict supply. This can induce the lack of competition described in the first concern or create artificial scarcity. This is primarily a concern in smaller capacity zones where green-field generation is difficult or more expensive to site (e.g. heavily populated areas or limited access to fuel delivery or transmission interconnection). In such cases, a brown-field site that once hosted a productive generation plant but no longer does, may be the least-cost siting option. An incumbent supplier may choose to keep such a site fallow, once the existing plant has ceased operation, in order to restrict supply of capacity in the smaller, citing constrained, zone.

A proposal that was tailored to address these two issues was brought to the NEPOOL Markets Committee in the Winter of 2015. While the proposal was less aggressive with triggering administrative pricing than are the current rules, it still leveraged an administrative pricing approach that, when triggered, could deviate from a single-price auction outcome and result in two-tiered pricing.

Below is a brief discussion of factors that reduce concern that market power can be exercised by new entry. The discussion is broken out into factors that are being proposed or are currently before FERC and factors that the ISO may consider as separate initiatives going forward.

Mitigating Factors

There are several factors present in the current proposal on sloped zonal demand curves and in the market rule changes filed at the FERC regarding retirement reform that reduce the concern that market power will be exercised in the Forward Capacity Market. These factors are generally competition improving or otherwise limit the extent to which market power can be exercised.

Lack of Competition Created by Retirement: Resource retirement under the current market rules can create a significant decrease in supply of existing capacity in an import-constrained zone. A retirement is not signaled to the market in sufficient time that new entry can choose to enter in the first auction where the retirement will be effective. In December, 2015, the ISO filed market rule

[1] Mitigation provisions currently exist that address the potential exercise of market power from existing resources and imports.

changes at the FERC that reform how capacity retirements are treated. In addition to providing protection against the exercise of market power through pre-mature retirement, the filed rule changes also adjust the timing of retirement and new entry in the qualification process. The changes provide information to the market regarding the quantity and location of capacity seeking to leave the capacity market through either retirement or permanent de-list bid. This information can improve competition in the capacity market through increased participation of new entrants in the current auction to contest the potential decrease in supply from intended retirements. The retirement reforms have not been approved by FERC at the time this memo was written.

Demand Curve Slope and Position: The slope of the demand curves in the ISO proposal do provide a degree of protection against price increase due to the exercise of market power and therefore reduce the incentive to exercise market power. This protection is more robust in import-constrained zones at higher quantities and is less robust as the zone becomes more deficient (relative to the Local Sourcing Requirement, or LSR). However, the most recent proposal embodies a set of reliability criteria that shifts the demand curve (relative to the prior proposal) to allow procurement below the LSR at prices below the auction starting price (on the sloped portion of the demand curve). This ensures there is price responsiveness in the demand curve at and quantities short of LSR which provides the mitigation property of a sloped demand curve in a procurement region that is in the neighborhood of the Local Sourcing Requirement.

Substitution Between Zones: The ISO proposal allows for capacity to be substituted among zones. This results in capacity resources from outside an import-constrained zone competing with resources within an import-constrained zone. Substitution among zones effectively increases the supply that is available to satisfy demand within an import-constrained zone, which improves competition and reduces the opportunity to exercise market power. While an important feature, as an import-constrained zone becomes more “deficient” relative to LSR it takes a more capacity outside of the zone to satisfy demand inside the zone. The ability to substitute capacity among zones does improve competition within an import-constrained zone, however this effect decreases as the zone becomes more deficient. Additional work is necessary to explore the extent to which the substitution allowed by the ISO proposal can limit the extent to which market power can be exercised in import-constrained zones.

Application of Social Welfare in Zonal Clearing: Introduction of sloped zonal demand curves also introduces the application of social welfare in clearing the marginal resource within an import-constrained zone. With vertical demand curves, the zonal requirement must be met and therefore a higher-priced marginal resource can be selected even if only a small portion of its capacity is required to meet the fixed requirement. The social benefit criteria will only procure from a marginal resource if doing so is social welfare improving. This makes the selection of a high-priced resource less absolute relative to a single quantity demanded (LSR in the vertical demand curve regime) and introduces risk that a resource offering above a competitive level may not clear in the auction if it is only marginally needed to meet demand. This reduces the opportunity for uncompetitive new entry to clear the auction and set an artificially high price.

Additional Mitigating Changes

There are additional factors that can be addressed by the ISO that will also improve competition in the capacity market and reduce the likelihood that market power can be exercised successfully.

Advanced Notice of Zone Definition: A new zone definition can result in uncompetitive supply, especially if the definition is driven by reliability criteria that are not met due to lack of existing capacity. If the new zone is not announced sufficiently in advance, developers of new generation projects may not have sufficient time to position projects to enter the capacity market in the first year the new zone applies. This can create uncompetitive supply conditions, where there are insufficient new entrants to create competition to meet the residual demand in the new zone, and expose the zone to the exercise of market power. To the extent changes in zone definitions can be established in advance and made public, this should be pursued by the ISO to provide potential new entry sufficient notice to respond and limit the extent of uncompetitive supply conditions precipitated by changes in capacity zone definitions.

Larger Import-Constrained Zones: The definition of capacity zones is driven by reliability criteria, not market criteria, and establishes the product differentiation that is necessary to appropriately value capacity in different reliability areas. However, smaller import-constrained zones can be more susceptible to uncompetitive supply as there are presumably fewer siting opportunities and a single resource of specific size represents a larger proportion of supply needed to meet the demand for locally sourced capacity. The ISO has recognized this relationship between zone size and competitiveness. To the extent that smaller zones are required to meet reliability criteria, additional measures may be required to ensure market power is not a factor in auction clearing. Announcing the zone sufficiently in advance is one potential measure. Additional measures, such as offer review of new capacity resources may also be warranted.

Sealed Bid Auction: The current descending clock auction format provides information between the offer rounds that can indicate to participants the extent to which their offers are needed to meet demand. This information can be used by new entry to offer at an uncompetitive price and clear their new and existing capacity at the higher price. Changing the auction format to a sealed-bid structure would eliminate the provision of this information to participants during the running of the auction, requiring participants to choose the lowest price at which they are willing to assume a Capacity Supply Obligation and submit that price prior to the execution of the auction. This may eliminate some ability for new capacity to successfully exercise market power in the capacity auction.

Offer Capping for New Capacity: An additional option is to limit the extent new entry can exercise market power through offer capping. This approach would apply mitigation to the individual resource and not to the auction clearing price. At a conceptual level, this type of offer cap could be applied in a similar fashion as the Minimum Offer Price Rule is currently applied to protect against buyer-side market power. For example, in the case of seller-side market power for new entry, a threshold is established (e.g. 20 percent above Net CONE) and new capacity resources wishing to offer above the threshold must have their offer reviewed and approved by the Internal Market Monitor. This would provide protection against the exercise of market power by new resources entering the capacity market without and does not need to be accompanied by an administrative pricing rules in order to be effective.

Position on Administrative Pricing Rules for the Current Initiative

There are several proposed market rule changes that either improve competition in the capacity market or provide protection against the exercise of market power. While it is paramount to ensure the capacity auction prices are not influenced by market power, it is also important to appropriately balance the potential for exercise of market power with the benefit of maintaining a single-price auction.[2] The proposed changes represent a significant improvement in the potential for competition in the capacity market compared to the landscape underlying the effort to extend administrative pricing under sloped zonal demand curves that was undertaken in the Winter of 2015. As noted above, there are additional steps that the ISO can take to further increase the likelihood of competitive supply in import-constrained zones and reduce the likelihood that capacity auction outcomes are influenced by the exercise of market power.

At this time, I am not proposing that the ISO implement administrative pricing along with the sloped zonal demand curves. While there are several factors identified above that are proposed or could be pursued by the ISO that would improve competition, my position rests heavily on the characteristics of the existing proposal, FERC approval of the ISO's filing on retirement reform, and the ISO maintaining larger capacity zones. In general, smaller zones are likely to have more concentrated capacity supply and may have limited siting options for new supply. Both of these factors reduce competition. For FCA 10, the ISO has not elected to apply smaller import-constrained zones. Should the ISO choose to define smaller import-constrained capacity zones, additional remedies may be warranted. An alternative approach to administrative pricing, some form of offer-capping for new entry, is discussed in the text above. This may be a preferred approach to administrative pricing as it can be tailored to target specific resources, not the pricing of the entire zone or market, which avoids the deleterious market impacts from tiered pricing while providing protection to the market against the exercise of market power.

[2] See the January 6, 2016, ISO memo to the NEPOOL Markets Committee "Administrative pricing rules under proposed demand curve design for FCA11" for a detailed discussion of the deleterious effects of administrative pricing and the tiered pricing that can result.

POTOMAC
ECONOMICS

MEMORANDUM

TO: NEPOOL Markets Committee

FROM: David Patton
Pallas LeeVanSchaick

DATE: January 11, 2016

RE: EMM Comments on ISO-NE's Zonal Demand Curve Proposal

ISO New England has developed a proposal for implementing sloped demand curves for its local capacity zones. This memo provides our preliminary comments on this proposal. Overall, we believe the proposal is theoretically sound and addresses the concerns we raised in our 2014 Assessment of the New England Electricity Markets. Further, it will substantially improve the performance of the ISO's capacity market, particularly in the local capacity zones. Nonetheless, we identify to factors that we recommend the ISO evaluate before finalizing the proposal.

A. Introduction

Capacity markets are designed to ensure that sufficient resources will be available to satisfy key planning requirements. Efficient capacity markets employ sloped demand curves to ensure capacity prices reflect the marginal reliability value of the ISO's resources. In doing so, the capacity market will provide revenues that, together with the energy and ancillary service markets, facilitate efficient investment and retirement decisions by participants.

Transmission system limitations make capacity more valuable in certain import-constrained areas. Accordingly, an efficient capacity market should produce locational prices that reflect the different values of capacity for satisfying locational planning reliability requirements in different areas. Likewise, capacity that is fully deliverable to end-users under peak conditions should receive higher prices than capacity that is sometimes not deliverable because of transmission limitations. Over time, a capacity market that sets prices in accordance with the value of capacity in each area will encourage more efficient investment and reduce costs to consumers.

The ISO has proposed a method for setting zonal demand curves in recent Markets Committee meetings. The proposal is based on three core principles: (1) that demand curves be set high enough to satisfy the planning reliability requirements of the system, (2) that the criteria for setting the demand curves be sustainable and produce efficient results even after future changes in the transmission system, and (3) that the demand curves be set in a cost-effective manner.

We have reviewed the ISO's proposal and find that it satisfies these objectives because the locational capacity prices will be determined in accordance with the marginal reliability value of capacity for satisfying locational planning reliability criteria. Therefore, local capacity prices will fall as resources are added in a particular zone, reflecting that each additional MW provides less incremental benefit.

Additionally, new resources in import-constrained areas will receive a higher price than capacity in other areas to the extent that they provide greater reliability value. Thus, if 1 MW of capacity in an import-constrained area provides the same reliability benefit as 2 MW of capacity in the "Rest of System" area, capacity prices in Rest of System should be one half of the prices in the import-constrained area. As future upgrades and other changes in the transmission system affect the value of capacity in each zone, this market framework will adjust demand curves accordingly.

In our opinion, the ISO's proposal is a significant improvement on the current vertical zonal demand curves, which do not reflect the true value of additional capacity in each zone as supply increases. The ISO's proposal would establish zonal demand curves that are based explicitly on the value of the capacity as reflected in the ISO's planning models. In doing so, it will provide incentives for investors to build and retain capacity where it is most valuable.

The remainder of this memo discusses aspects of the ISO's proposal and concerns that have been raised by stakeholders. In particular, we discuss how the proposed zonal demand curves would:

- Address concerns about local market power in import-constrained capacity zones (given other significant market rule changes in recent years);
- Eliminate the need for the administrative pricing rules; and
- Affect future capacity revenues and price volatility.

B. Eliminating Administrative Pricing Rules and Mitigating Market Power in Import-Constrained Zones

The administrative pricing rules were adopted to address significant market inefficiencies that could arise from the vertical characteristics of the legacy demand curves. The Insufficient Competition ("IC") and Inadequate Supply ("IS") Rules limited the potential harm to consumers if a supplier exercised market power in the FCA, while the Capacity Carry Forward ("CCF") Rule limited the tendency for prices to drop precipitously in years following new entry. Although these administrative pricing rules may limit the effects of market power and price volatility in some cases, they may also have adverse distortionary effects on market clearing prices. Thus, a key benefit of the ISO's proposal is that the rationale for the administrative pricing rules will be eliminated.

1. Insufficient Competition and Inadequate Supply Rules

When a demand curve is established that reflects the true marginal reliability value of resources to the ISO market, then the demand curve will establish an efficient price when there is inadequate supply. Therefore, any reduction in the capacity clearing price by the IS Rule would be a distortion that would, in the long-run, undermine the market's ability to efficiently attract and retain resources. The IC Rule has a similar effect in artificially suppressing the capacity prices. Both of these rules reduce suppliers' expectations of future capacity prices, which should lead new suppliers to require higher prices in the initial year of entry and lead existing suppliers to retire sooner than they should.

Because these administrative pricing rules create issues when applied in a market with a sloped demand curve, the ISO eliminated the IC and IS Rules at the system level when it created the system demand curve. Some may argue that the IC Rule should be retained to address potential market power. However, the IC Rule is not an effective deterrent to a supplier with market power in the capacity market. If a supplier is pivotal and has raised its offer to raise clearing price, the IC rule would not reduce the price paid to that supplier. Hence, it does not address the underlying incentive for such suppliers to exercise market power. The administrative pricing rules are no substitute for effective market power mitigation rules.

Additionally, several market rule changes have been filed to mitigate market power and reduce barriers to competition since the administrative pricing rules were originally adopted.

1. Use of a sloped demand curve (rather than a vertical one) will reduce the expected price effect if a supplier attempts to withhold. [1]
2. The capacity performance incentives have significantly changed the incentives for capacity suppliers and increased the price elasticity at "the top of the supply stack". The additional price elasticity should reduce market power.
3. Existing resources are subject to much more stringent delist bid caps than in the original FCM rules. [2]
4. Resources proposing to retire will be subject to new limitations if recently proposed tariff revisions are accepted by the Commission. [3]

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[1] This is illustrated on pages 88-91 in our *2014 Assessment of the ISO New England Electricity Markets*, June 2015, Potomac Economics.

[2] When the IC and IS Rules were first implemented, existing suppliers could raise their dynamic delist bids to 80 percent of Net CONE without undergoing review by the IMM. Under the current rules, the IMM reviews delist bids above the Dynamic Delist Bid Threshold Price, which is much lower relative to the competitive offer level for most generators (i.e., the going-forward costs of the generator, including opportunity costs of selling capacity).

5. Barriers to competition from new resources will be reduced if the Commission accepts recently proposed process changes which will allow generators to submit a Show of Interest after public notice of any proposed retirements.[4]

Notwithstanding these market enhancements, we have recommended additional changes in the FCM process that would reduce barriers to competition and avoid publication of information that might facilitate strategic bidding behavior. [5]

In conclusion, we support the elimination of the IC and IS Rules because we find that they are no longer necessary under the ISO's proposed zonal demand curves. If retained, these rules would impair market efficiency precisely when capacity market investment signals are most critical for stimulating efficient investment.

2. Capacity Carry Forward Rule

The CCF Rule was adopted to reduce the tendency for prices to drop precipitously in years following new entry. However, the sloped demand curve provides a superior mechanism for reducing inefficient sources of price volatility following new entry. This is because the sloped demand gradually falls as the amount of surplus capacity increases such that clearing prices will provide an accurate reflection of the marginal value of capacity after new entry. If the price falls, it will be to a level that reflects the marginal value of capacity. Hence, the CCF rule is no longer needed or desirable.

C. Shape of the Demand Curves and the Volatility of Capacity Prices

The ISO has proposed convex demand curves whose shape is based on how increasing quantities of resources in various locations affect reliability (i.e., the probability of losing load), while other markets have adopted linear curves or segmented curves. The convex curves proposed by the ISO will affect the capacity clearing prices over time and the revenues suppliers in New England will expect to receive. We discuss these effects and our opinion regarding the shape of the proposed demand curves in the following sections.

1. Effect of Convex Demand Curves on Revenues

The convex demand curve that the ISO has proposed for the system exhibits two noticeable differences from the current system demand curve. First, the proposed system demand curve is steeper at capacity quantities close to (or less than) the NICR and flatter when system cleared surplus capacity is greater than about 3 percent of the NICR.

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3 See *ISO New England Inc.*, Docket No. 16-551-000, *Forward Capacity Market Retirement Reforms*, December 17, 2015.

4 *Id*.

5 See discussion of Recommendation #10 on pages 13-15 and 91-97 in our *2014 Assessment of the ISO New England Electricity Markets*, June 2015, Potomac Economics.

Second, the proposed system demand curve sets a lower clearing price than the current curve for a given amount of cleared capacity, except when cleared surplus capacity is greater than 8 percent of the NICR or the ISO clears capacity less than the NICR by more than 1 percent. Hence, one might conclude that the proposed convex system demand curve would reduce the revenues that suppliers would expect from the New England capacity market. However, this is only likely to be correct in the short-term and occurs because the proposal would shift a larger share of capacity procurements to the import-constrained areas where capacity provides greater reliability benefits.

In the long-term, this would lead to a slightly lower equilibrium level of capacity outside of the import-constrained areas than the current system demand curve. However, the proposal should provide a similar level of expected revenues once the market achieves the long-run equilibrium.

2. Effect of Convex Demand Curves on Price Volatility

The second effect of the convex shape of the proposed demand curves is that it will increase the volatility of the capacity prices. Price volatility can increase the cost of supply in a commodity market because it increases the market risk for investors making capital expenditures. Investors will generally have higher capital costs and incorporate larger risk premiums before investing in a volatile market.

However, price volatility that is driven by underlying fundamentals of supply and demand is expected and even beneficial. Hence, while it is important to avoid artificial price volatility that is driven by artifacts of the market design, it is equally important to not suppress price volatility that is driven by market fundamentals.

Because the proposed shapes of the demand curves are a reflection of the planning criteria employed by the ISO, we are not concerned that the resulting price volatility will be excessive or inconsistent with the underlying reliability value of the product. The convex shape of the proposed demand curves results from the planning models, which predict that the risk of load shedding increases sharply as capacity levels fall below the LSR or NICR. Hence, the resulting price volatility should be an accurate reflection of market fundamentals rather than a result of an inefficient market design.

Additionally, some of the concerns about price volatility should be ameliorated by the phase-in of the capacity performance incentive rules. Under the new performance incentive rules, a supplier that accepts a Capacity Supply Obligation gives up the opportunity to earn additional large capacity performance payments during shortages. Consequently, suppliers will have a significant opportunity cost of selling capacity in the FCA that depends on the PPR ("Performance Payment Rate"). When the PPR is increased to $5,550/MWh beginning in FCA 11, the quantity of delist bids and offers at levels near the capacity clearing price should rise substantially, thereby increasing the elasticity of supply and moderating price volatility.

Although the ISO's proposal is generally sound, we recommend the ISO evaluate two issues that might lead to excess price volatility before finalizing its proposal. First, we recommend the ISO consider how price volatility may affect the capital costs of investors in both new and existing resources. If this interaction is considered, it may indicate that the slope of the demand curve should be flattened to some degree. [6]

Second, we recommend the ISO consider adjusting the demand curves to account for elements of the planning models not explicitly reflected in the ISO's estimates of the MRI ("Marginal Reliability Impact"). Under the ISO's proposal, the zonal demand curves would set the differential between a zone clearing price and the system clearing price based solely on the amount of capacity in the zone. However, the actual marginal reliability value of capacity in the local zone also depends on that amount of capacity in other zones. While such inter-zonal effects are too complex to capture explicitly in the capacity market design, we recommend the ISO consider whether such effects would tend to justify an adjustment to flatten the demand curves to some degree.

D. Conclusions

The ISO's proposal is theoretically sound and would be a significant improvement on the current market design. If its proposal is adopted, New England would have the first capacity market that set prices based explicitly on the reliability metrics that underlie the planning requirements (i.e., the probability of losing load). Additionally, the ISO's proposal addresses our previous concerns regarding the interaction between the zonal demand curves and the system-wide demand curve. [7] Finally, we fully support the ISO's proposal to eliminate the administrative pricing rules as a part of its proposal to implement sloped demand curves.

Notwithstanding our overall support for the ISO's proposal, we do recommend that the ISO evaluate two factors that may affect the slope or shape of the zonal demand curves before finalizing the proposal:

- How price volatility affects the capital costs of investors in both new and existing resources.
- Whether to adjust the demand curves to account for elements of the planning models not explicitly reflected in the ISO's estimates of the Marginal Reliability Impact.

If one or both of these factors appears to have a significant impact on the capacity market incentives, then we recommend the ISO adjust the demand curves accordingly.

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6 ISO-NE recently posted material related to its assessment of price volatility, but we were unable to review this material carefully before the publication of this memo.

7 See discussion on pages 15-16 and 97-101 in our *2014 Assessment of the ISO New England Electricity Markets*, June 2015, Potomac Economics.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool Participants Committee	)))))	**Docket No. ER16-____-000**

PREPARED TESTIMONY OF ALAN MCBRIDE ON BEHALF OF ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

Q: Please state your name, position and business address.

A: My name is Alan McBride. I am Director, Transmission Strategy and Services with ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: Please describe your work experience.

A: I joined the ISO in June 2006. During my first four years at the ISO my primary responsibility was as Project Manager of New Generation Qualification for the Forward Capacity Market ("FCM"). In 2010, I became the Manager, Area Transmission Planning for northern New England. In January 2014, I provided testimony to the Commission in support of the filing of the Capacity Zone formation methodology that is still in place at this time. I have led the implementation of the Capacity Zone formation process. I am currently the Director of Transmission Strategy and Services and am responsible for the oversight of the interconnection process for new generators and new elective transmission upgrades.

Before joining the ISO, I worked at Dynegy and then at Calpine. At Dynegy and Calpine, I supported various transmission-related activities associated with the development, interconnection and commercial operation of merchant generators. Before joining Dynegy, I worked at Power Technologies Incorporated (now a division of Siemens), where I conducted various transmission analysis studies, including the system impact studies of several proposed generating facilities. I have over 20 years of experience in various aspects of power transmission system analysis and transmission services. I hold a B.S. in Electrical Engineering from University College Dublin, in Ireland, an M.S. in Electric Power Engineering from Rensselaer Polytechnic Institute and an M.B.A from Purdue University.

II. PURPOSE AND ORGANIZATION

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to explain the identification of the appropriate transmission transfer capability between a constrained capacity zone and the rest of the system under the new Demand Curve Design Improvements. The primary purpose of the Demand Curve Design Improvements is to provide for the use of sloped demand curves for constrained capacity zones in the FCM. The new sloped zonal demand curves replace the use of fixed zonal capacity requirements (the fixed zonal requirements are also referred to as "vertical" demand curves). As explained in this testimony, it is necessary to identify an appropriate transfer capability methodology for purposes of implementing the new sloped zonal demand curve approach.

Q: What role did you play in identifying an appropriate transfer capability methodology under the Demand Curve Design Improvements?

A: I developed the transfer capability methodology explained in this testimony and served as the ISO's subject matter expert for purposes of explaining the methodology and related aspects of the Demand Curve Design Improvements to New England stakeholders. The transfer capability methodology is one element of the broader Demand Curve Design Improvements. A comprehensive explanation of the broader Demand Curve Design Improvements is provided in the accompanying Geissler-White Testimony.

Q: How is your testimony organized?

A: In the next section of the testimony, Section III.A, I explain how the existing fixed capacity requirements are determined for import-constrained zones, including how transfer capability is treated for purposes of determining the existing fixed requirements. Section III.B explains how the same principles used to determine the existing fixed requirements for import-constrained zones are applied to identity the appropriate transfer capability that should be used for purposes of the new sloped demand curves applied to import-constrained zones. Section III.C describes the treatment of export-constrained capacity zones.

Section III.D discusses the expected reliability outcomes under the Demand Curve Design Improvements.

III. TRANSFER CAPABILITY FOR SLOPED DEMAND CURVES FOR CONSTRAINED ZONES

A. <u>Existing treatment of transfer capability for import-constrained zones</u>

Q: At a high level, please explain how transfer capability is used to help determine the fixed zonal capacity requirements that are currently used in the FCM.

A: Under the current FCM structure, the Local Sourcing Requirement serves as a fixed zonal capacity requirement for import-constrained zones and the Maximum Capacity Limit acts as the maximum quantity that can be procured in export-constrained zones. The method for determining the Local Sourcing Requirement for import-constrained zones is set out in Section III.12.2.1 of the market rules and is the higher of two values: (1) the Local Resource Adequacy Requirement ("LRA"), and; (2) the Transmission Security Analysis Requirement ("TSA"). The method for determining the Maximum Capacity Limit for export-constrained zones is set out in Section III.12.2.2 of the market rules. For both import-constrained and export-constrained zones, the fixed zonal requirements are determined through system modeling analysis that considers the transfer capability between the constrained zone and the rest of the system.

Q: How are transfer capabilities calculated under the existing rules?

A: The ISO calculates transfer capabilities pursuant to the North American Electric Reliability Corporation ("NERC") Standard FAC-013-2 "Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon." FAC-013-2 is designed to ensure that Planning Coordinators have a methodology that they use to perform an annual assessment to identify potential future transmission system weaknesses and limiting facilities that could impact the Bulk Electric System's ability to reliably transfer energy in the Near-Term Transmission Planning Horizon. When identifying potential future New England Transmission System weaknesses, consideration is given to rejected de-list bids, generation retirements or other changes in system conditions, such as new generation resources or transmission upgrades. The "Methodology Document for the Assessment of Transfer Capability"[1] describes all of the relevant conditions and assumptions that are used in the development of transfer capabilities. The methodology document describes the calculation of first-contingency (N-1) and second-contingency (N-1-1) transfer capabilities. Transfer capabilities are key inputs to the development of the existing fixed zonal capacity requirements.

Q: What contingencies are used in N-1 and N-1-1 transfer capabilities calculations?

A: In accordance with the ISO's planning criteria and consistent with NERC and Northeast Power Coordinating Council (NPCC) planning criteria, N-1

[1] http://www.iso-ne.com/static-assets/documents/2016/01/technical_guide_appendix_i_2016_01_14.pdf

contingency testing analyzes the effects of the sudden loss of a transmission element or a generating unit. N-1-1 contingency testing analyzes the loss of a second transmission element or generating unit, after the loss of the first element.

Q: Why does the existing approach for import-constrained zones use a methodology based on the "higher of" LRA or TSA?

A: As noted earlier, the ISO uses a fixed capacity requirement for import-constrained zones known as the Local Sourcing Requirement, which is the higher of two different assessment methods (LRA and TSA). As explained below, these two assessments and their associated requirements are based on two different analytical methodologies and complementary reliability needs. Each of these assessments forms an important part of the ISO's resource adequacy planning process.

Q: Explain the first assessment method (LRA) and how capacity transfer capability is used in this assessment.

A: LRA is the minimum capacity necessary in an import-constrained zone to ensure the system (not the zone itself) satisfies the 1-day-in-10 Loss of Load Expectation ("LOLE")[2] planning standard when the system as a whole has capacity equal to the Installed Capacity Requirement (net of HQICCs), referred to hereafter as "Net ICR"). The LRA value depends expressly on the transfer capability value for the import-constrained zone. The calculation of the LRA value is based on a

[2] More precisely, the LRA is the zonal capacity value that yields an LOLE no greater than 0.105.

probabilistic analysis that uses a full-scale reliability planning simulation system (known as Multi-Area Reliability Simulation, or "MARS") to simulate unit outages and loads (both zonally and system-wide). For purposes of calculating the LRA, the ISO uses the N-1 transfer capability value into the import-constrained zone. This procedure for establishing the LRA is set forth in detail in Section III.12.2.1.1 of the market rules.

Q: Provide an example of an LRA calculation.

A: For FCA 10, the N-1 transfer capability into the Southeast New England Capacity Zone was 5,700 MW. Using the MARS methodology to identify the minimum capacity necessary in an import-constrained zone to ensure the system satisfies the 1-day-in-10 LOLE, the resulting LRA for the Southeast New England Capacity Zone was 9,584 MW.

Q: Would the LRA value in the example set the requirement in FCA 10 for Southeast New England Capacity Zone?

A: No. Importantly, the capacity requirement is not necessarily set at the LRA value. As noted at the outset, a second assessment (TSA) is performed and the higher of the LRA and TSA value is used.

Q: Explain the TSA determination and how transfer capability is used in this assessment.

A: The Transmission Security Analysis assessment is a deterministic reliability screen used for an import-constrained area. The TSA assessment determines how much internal generation (located within the zone) and import capacity is needed to meet a fixed amount of assumed load in the import-constrained zone. The calculation is performed using a series of discrete transmission load flow study scenarios. In performing the analysis, static transmission interface transfer limits may be established as a reasonable representation of the transmission system's capability to serve sub-area load with available existing resources. Unlike the LRA assessment, which is based on a probabilistic modeling of forecasted load and resource availability, the results of the TSA assessment are presented in the form of a deterministic operable capacity resource analysis for the fixed assumed level of load.

Among the many variables used in the TSA assessment is an estimate of the import capability into the import-constrained zone. As described above, in accordance with ISO, NERC and NPCC criteria, the TSA assessment uses two N-1-1 transfer capabilities that are based on: (1) the loss of the largest generating unit and the most critical transmission element ("Line-Gen"), and; (2) the loss of the most critical transmission element followed by loss of the next most critical transmission element ("Line-Line").

The detailed conditions used for calculating the TSA are contained in ISO New England Planning Procedure No. 10 (Planning Procedure to Support the Forward Capacity Market).

Q: Provide an example of a TSA calculation.

A: As noted above, for FCA 10 the N-1 transfer capability into the Southeast New England Capacity Zone was 5,700 MW. The N-1-1 transfer capability was 4,600 MW. The TSA assessment determined the quantity of capacity inside the zone that, when combined with imports from outside the zone (under second contingency conditions), would be needed to serve the assumed load within the zone. The resulting TSA was 10,028 MW.

As noted earlier, the LRA for FCA 10 for the Southeast New England Capacity Zone was 9,584 MW. Since the Local Sourcing Requirement is set at the higher of the LRA and the TSA, the Local Sourcing Requirement for the Southeast New England Capacity Zone for FCA 10 was 10,028 MW.

Q: Why is the Local Sourcing Requirement set at the higher of LRA or TSA?

A: The different analyses and their associated requirements are based on two different analytical methodologies and complementary reliability needs. The LRA calculation is a determination of resource needs in a zone using data and probabilistic mathematics that capture the assumed uncertainties associated with demand and resource availability to meet the resource adequacy planning standard. The TSA assessment is a determination of resource needs in a zone using deterministic load flows that capture the ability of the zone to meet its load through internal generation and import capacity under a discrete set of operating conditions, consistent with transmission security planning criteria. The current LSA and TSA analyses are two distinct ways of determining the resource needs in a local area and each should be reflected in the FCM design. The use of the "higher of" methodology under the current FCM design was approved by the Commission in 2010.[3]

Q: Why is it important to understand the existing methodology for calculating the fixed zonal requirements when considering how transfer capability should be reflected in the new sloped zonal demand curves that will be used for constrained zones?

A: It is important to understand that the existing methodology considers transfer capability in several different ways for purposes of calculating the fixed zonal requirements. The current process for calculating requirements for import-constrained zones does not simply use the N-1 import limit to determine the transfer capability used to set the zonal capacity requirement. Instead, the current treatment uses detailed methodologies that account for both first contingency conditions (the N-1 import limit) and second contingency conditions (N-1-1 import limits) in determining the zonal capacity requirement. This "higher of" methodology appropriately accounts for the various actual transfer capabilities.

[3] *ISO New England Inc.*, 131 FERC ¶ 61,065 (2010), *order on reh'g and clarification*, 132 FERC ¶ 61,122 (2010).

In the next section, we explain how these methodologies can be readily adapted to the demand curve design described in the Geissler-White Testimony, in which downward-sloping demand curves are used for import-constrained zones.

B. <u>Identifying the appropriate transfer capability for import-constrained capacity zones under the Demand Curve Design Improvements</u>

Q: Why is it necessary to develop a new methodology for assessing transfer capability for purposes of designing the new sloped zonal demand curves?

A: It is critical to identify the correct transfer capability for use with sloped demand curves in the capacity market. In effect, with the Demand Curve Design Improvements, the FCM is moving from a design that uses a single-valued capacity requirement for import-constrained zones to a design in which there is a variable capacity requirement for an import-constrained zone. The new variable requirement is specified by the zonal demand curve and depends on price. Neither of the fixed requirement methodologies (LRA and TSA), if applied directly, are fully compatible with the variable requirement specified by a sloped demand curve. The LRA and TSA assessments both yield only single-valued capacity requirements and the two methods incorporate several different transfer capabilities into the final result (N-1, N-1-1 Line-Gen and N-1-1 Line-Line). Nonetheless, as explained in the remainder of this section of the testimony, the logic of the existing LRA and TSA methods can be readily adapted to determine a transfer capability that is appropriate for use with sloped demand curves for import-constrained zones.

Q: How can the LRA and TSA assessments be adapted for use with sloped zonal demand curves?

A: As explained in Section V of the Geissler-White Testimony, the new sloped zonal demand curves reflect the Marginal Reliability Impact (or "MRI") of incremental capacity in different locations. To estimate the MRI value that corresponds with each capacity level in an import-constrained zone, MARS requires that a transfer capability across the zonal interface be specified. For import-constrained zones, it is important that the capacity transfer capabilities continue to reflect certain underlying reliability assessments (*e.g.*, the various N-1, N-1-1 Line-Gen, and N-1-1 Line-Line contingency scenarios) that are currently reflected in the calculation of the LRA and TSA.

The Demand Curve Design Improvements identify this transfer capability while accounting for both the LRA and TSA assessments as follows. Initially, the N-1 transfer capability that is currently used in determining the LRA is employed for purposes of the zonal MRI calculation. However, if the TSA exceeds the LRA, then the transfer capability for the import-constrained zone used in the MRI calculation will be set based on the N-1 import limit used to calculate the LRA value minus the positive difference between the TSA and LRA (TSA minus LRA). If the TSA is higher than the LRA, this yields a *lower* transfer capability to be used in the MRI calculation for the import-constrained zone and – other things equal – will result in an increase in the amount of capacity needed within the zone and a higher demand curve price. This is the same effect as the "higher of" methodology under the existing rules. In other words, by starting with the transfer limit used in the LRA assessment, and allowing this limit to be adjusted to account for the TSA assessment, the MRI-based curves continue to use a methodology that accounts for both LRA and TSA requirements.

Q: Please provide an example, using the new formula, of how transfer capability is reflected in the new sloped demand curves for import-constrained zones.

A: For FCA 10, the Southeast New England Capacity Zone N-1 transfer capability was 5,700 MW and the N-1-1 transfer capability was 4,600 MW. The LRA for the Southeast New England Capacity Zone was 9,584 MW and the TSA was 10,028 MW. The positive difference between the TSA and the LRA was 444 MW. When 444 MW is subtracted from 5,700 MW (the N-1 transfer capability), the result is 5,256 MW. This is the transfer capability that would be used to calculate the MRI values for various capacity levels in Southeast New England.

The indicative MRI curves for the Southeast New England Capacity Zone that are discussed in Section V of the accompanying Geissler-White Testimony are based on this methodology and specific transfer capability.

Q: Is the new approach for treating capacity transfer capability consistent with the approach that was used for purposes of calculating fixed zonal requirements?

A: Yes. The core idea is that this method maintains the same "higher of" logic that is currently employed in the ISO's reliability planning methods for import-constrained zones. Specifically, it continues to account for N-1-1 conditions considered in the TSA assessment in determining a capacity zone's transfer capability by enforcing a reduction in the transfer limit from the N-1 value used in the LRA assessment when the 'higher of' methodology sets the Local Sourcing Requirement based on the TSA. As can be seen from the example above, this method will generally result in a capacity transfer capability that either equals the N-1 import limit or that falls between the N-1 import limit and the N-1-1 import limit.

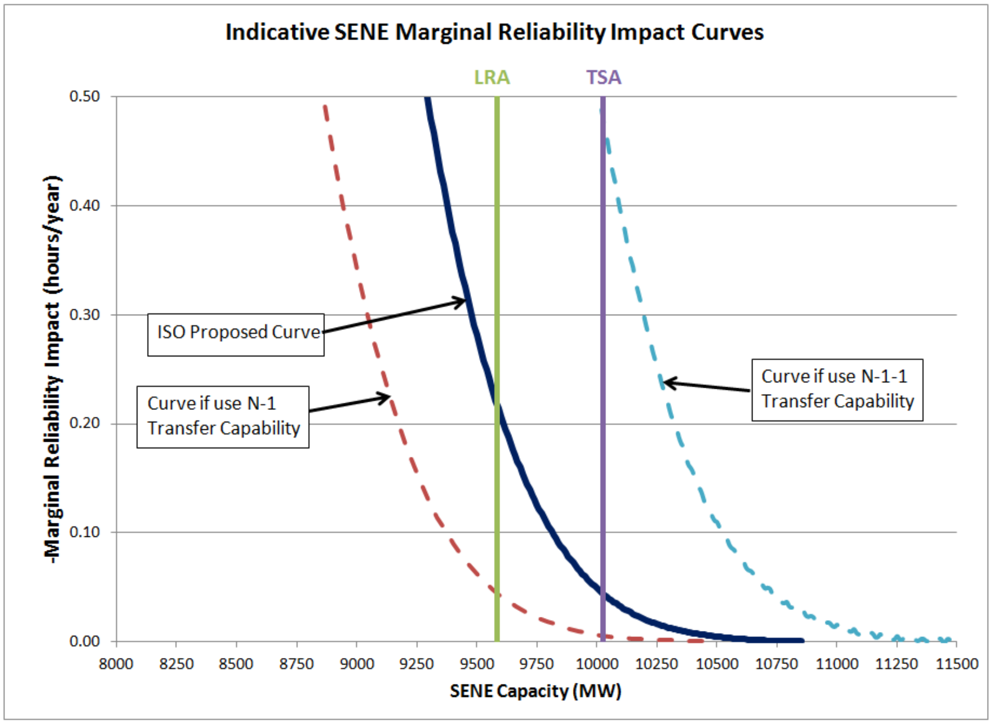
Q: Explain how capacity transfer capability will be used to specify the shape of a sloped demand curve for an import-constrained zone.

A: Section V of the Geissler-White Testimony discusses how the ISO will use its reliability planning simulation model, MARS, to determine the shape of sloped demand curves for the system and for each constrained capacity zone. As explained, the new sloped demand curves are determined based on MRI values.

For an import-constrained zone, a key input into the reliability planning simulation model is the transfer capability between the import-constrained zone and the Rest-of-Pool Capacity Zone. The transfer capability valued explained above is used in the reliability planning simulation model to determine the MRI curve for the import-constrained zone. As a final step, and as further explained in the Geissler-White Testimony, after the MRI curve for an import-constrained zone is determined, the demand curve for that zone is calculated by converting the MRI values to prices using a simple scaling factor.

For an import-constrained zone, the MRI-based curve expresses the marginal increase in overall reliability, as measured by the change in expected energy not served, when additional capacity is procured in the import-constrained zone instead of procuring additional capacity in the Rest-of-Pool Capacity Zone.

The following graph depicts how MRI-based curves would be calculated in the case of the Southeast New England Capacity Zone (referred to as “SENE” in the graph) for FCA 10. The vertical lines depict the LRA and TSA values from FCA 10. The solid curve depicts an MRI-based curve for the zone. The graph also shows the effect of using different transfer capability assumptions. As the transfer capability into the import-constrained zone is reduced, the curve maintains the same overall shape – but shifts to the right to account for the fact that to meet the same demand, more capacity must be generated inside the zone.



Q: Is it appropriate to use a transfer capability at the N-1 import limit for purposes of determining the sloped demand curves for import-constrained zones?

A: No. Using only an N-1 import limit would inadvertently and systematically lower the reliability planning standards associated with import-constrained zone, by failing to account for second contingencies when determining the new MRI-based curves for import-constrained zones.

Q: Is it appropriate to use a transfer capability at the N-1-1 import limit for purposes of determining the sloped demand curves for import-constrained zones?

A: No. Using an N-1-1 limit would inadvertently increase the *de facto* reliability standard for import-constrained zones as a whole – well above the levels of reliability procured under the current "higher of" methodology. The graph above shows that an MRI-based curve using N-1-1 limits results in higher capacity requirements than the TSA value over almost all of the modeled conditions. The ISO tested additional capacity zones that have been modeled in the FCM in the past (but using updated topology/contingencies) and found that using the N-1-1 limit would result in substantially higher capacity requirements under all modeled conditions (*e.g.*, at any possible zonal clearing price). Thus, using the N-1-1 limit is not appropriate insofar as it is not the intent of the Demand Curve Design Improvements to increase overall zonal reliability standards.

Q: What is the appropriate method of treating transfer capability for purposes of determining the sloped demand curves for import-constrained zones?

A: An appropriate method should continue to reflect the "higher of" transfer capability methodology that considers both N-1 and N-1-1 contingencies. As explained above, the Demand Curve Design Improvements adopt a method of identifying transfer capability for import-constrained zones that reflects both LRA and TSA requirements.

Q: Have you evaluated the impact of capacity transfer capability on the performance of MRI-based curves for different import-constrained zones from a reliability perspective?

A: Yes. Evaluations were performed based on the calculations to determine the MRI curves for a number of historically import-constrained zones in the New England system using the new methodology. In addition to Southeast New England shown above, the evaluations included capacity zones for several regions – Connecticut, NEMA/BOSTON and SEMA/Rhode Island. These evaluations showed that the MRI-based curves have robust performance under a number of different zonal configurations.

C. <u>Treatment of capacity transfer capability for export-constrained capacity zones</u>

Q: How are capacity limit calculations conducted for export-constrained zones?

A: For export-constrained zone, a Maximum Capacity Limit ("MCL") is calculated using a similar probabilistic approach to the calculation of LRA for import-constrained zones that was described above. The MCL calculation has always made use of the N-1 transfer capability out of the export-constrained zone. In particular, there is no TSA-type methodology currently employed to determine the capacity transfer capability for an export-constrained zone and there is no consideration of N-1-1 transfer capability. Therefore, the existing method of setting transfer capability for fixed export limits can be applied directly to the new MRI-based design of sloped demand curves for export-constrained zones.

Q: How is capacity transfer capability reflected in the new sloped demand curves for export-constrained zones?

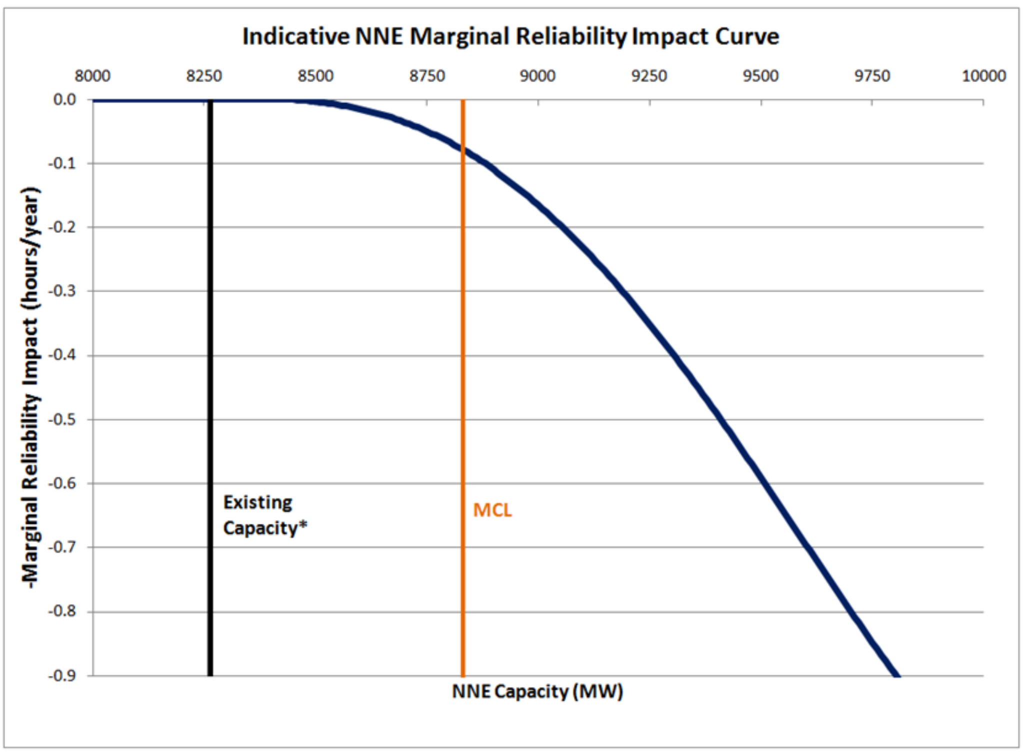
A: The proposed method will use the same transfer capability (that is used in the MCL) as the assumed input into the MRI-based curve calculations for an export-constrained zone. The general method is explained in Section V.D of the Geissler-White Testimony.

First, the N-1 transfer capability for the export-constrained zone is calculated. This value is used in the reliability planning simulation model (MARS) to calculate the MRI-based values for the export-constrained zone. For an export-constrained zone, the MRI-based curve expresses the marginal decrease in overall reliability, as measured by the change in expected energy not served, when additional capacity is procured in the export-constrained zone instead of procuring additional capacity in the Rest-of-Pool Capacity Zone. Once the MRI values for the export-constrained zone are determined, the demand curve for the export-constrained zone is determined in the same way as all demand curves under the new methodology, by converting the MRI values into prices using the appropriate scaling factor.

The central design principles underlying this methodology, and additional details concerning the implementation, are explained in Sections IV and V of the Geissler-White Testimony.

Q: Provide an example of the Marginal Reliability Impact calculation for an export-constrained zone.

A: The following graph shows MRI values that would have been associated with a Northern New England Capacity Zone ("NNE") under FCA 10 conditions. The N-1 capacity transfer capability for NNE was 2,675 MW and the indicative MCL was 8,830 MW for FCA 10. The following graph depicts the resulting MRI-based curve for an indicative Northern New England Capacity Zone along with the other relevant values.



A potential MRI-based curve that would be associated an export-constrained zone for Maine also was evaluated. A Maine export-constrained zone was not modeled in FCA 10 and is not proposed to be modeled in FCA 11. However, the evaluation of an MRI-based curve for a potential Maine export-constrained zone was used to ensure that the MRI-based curves have robust performance under a number of different zonal configurations.

D. <u>Reliability Outcomes Under the Demand Curve Design Improvements</u>

Q: Are any changes proposed to the conduct of reliability reviews for resource retirements and de-list bids as part of the Demand Curve Design Improvements?

A: No changes are proposed to reliability review of de-list bids or retirements as part of the Demand Curve Design Improvements. The existing rules continue to apply and a de-list bid shall not be rejected for reliability solely on the basis that acceptance of the de-list bid may result in the procurement of less capacity than the amount specified by the zonal demand curve (or the TSA or LRA). The ISO remains comfortable with continuing to not reject de-list bids for reliability to meet the TSA or LRA because when the zone falls below these quantities, the MRI-based zonal demand curves for an import-constrained zone will specify a price premium that may induce new entry; furthermore, the Demand Curve Design Improvements more fully reflect the partial substitutability of capacity across zones, which allow the system to meet its resource adequacy planning standards while procuring more capacity in the Rest-of-Pool Capacity Zone, and less in an import-constrained zone. An example illustrating this point is provided in Section VII of the Geissler-White Testimony.

Local (that is, sub-zonal) reliability reviews will continue to be conducted pursuant to the deterministic application of the applicable ISO, NERC and NPCC criteria. The new design does not change or impact this feature. De-list bids still may only be rejected for local reliability reasons if there is no associated resource substitutability, so long as the need is not associated with a capacity zone boundary constraint modeled for resource adequacy. In cases that do not involve resource adequacy, the ISO may seek to retain resources irrespective of whether the zone is long or short of TSA or LRA, and regardless of what level of capacity cleared pursuant to the zonal demand curve.

IV. CONCLUSION

Q: Does this conclude your testimony?

A: Yes.

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

Executed on April 15, 2016.

[signature]
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