



April 1, 2014

BY ELECTRONIC FILING

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

RE: **ISO New England Inc. and New England Power Pool, Docket No. ER14-000, Demand Curve Changes** -

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act (“Section 205”),¹ ISO New England Inc. (the “ISO”), joined by the New England Power Pool (“NEPOOL”) Participants Committee² (together, the “Filing Parties”),³ hereby electronically submit this transmittal letter and revised Tariff sections to establish a system-wide sloped demand curve and related parameters for use in New England’s Forward Capacity Market (the “Demand Curve Changes”). As explained further below, the Demand Curve Changes will become effective on June 1, 2014 and will be used in the Forward Capacity Auction that is to be held in February 2015 (“FCA 9”). As discussed in Section I of this filing letter, a June 1, 2014 effective date and the issuance of a Commission order on or before that date are required so that changes associated with the FCM qualification process are in place before associated qualification deadlines.

The impetus for this filing is an order issued by the Commission on January 24, 2014 that addressed the administrative pricing rules governing Inadequate Supply and

¹ 16 U.S.C. § 824d (2006 and Supp. II 2009).

² Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff (the “Tariff”), the Second Restated New England Power Pool Agreement, and the Participants Agreement. Market Rule 1 is Section III of the Tariff.

³ Under New England's Regional Transmission Organization (“RTO”) arrangements, the rights to make this filing of changes to the Market Rule under Section 205 of the Federal Power Act 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 this Section 205 filing.

Insufficient Competition that, if triggered, would apply to the Forward Capacity Auction that was held in February 2014 (“FCA 8”).⁴ In that proceeding, the Commission acknowledged the ISO’s view that a sloped demand curve could be a long-term solution to the problems associated with administrative pricing provisions and noted the ISO’s intention of submitting a sloped demand curve for Commission approval in the summer of 2014.⁵ However, the Commission expressed concern that waiting until the summer to submit a sloped demand curve “would not allow sufficient time for implementation by FCA 9.”⁶ Accordingly, the Commission directed the ISO to submit a sloped demand curve well before the summer. Specifically, the Commission stated:

Given ISO-NE’s explanation that a sloped demand curve will address the difficult and challenging issues presented here, and based on ISO-NE’s statements that its proposal here is intended to be temporary and address concerns for FCA 8, we will direct ISO-NE to submit its proposed demand curve by April 1, 2014, to allow sufficient time for implementation prior to FCA 9.

January 24 Order at P 30.

In this filing, the Filing Parties, supported by all six New England states, are submitting a package of rule changes to establish a fully-functioning system-wide sloped demand curve construct in New England’s Forward Capacity Market. As discussed more fully in Section IV, the Demand Curve Changes include several elements. First, the changes define the shape of the system-wide sloped demand curve in which the key points are defined by the estimated cost of entry for a new capacity resource (referred to as CONE in the rules) and well-established system planning design criteria that are used to ensure resource adequacy. Second, the changes extend the period during which a Market Participant may “lock-in” the capacity price for a new resource from five to seven years. Third, the changes establish a limited exemption from the buyer-side capacity market mitigation rules for certain renewable resources that are built to advance state environmental policy objectives (the “renewables exemption”). Finally, the changes eliminate, at the system-wide level, the administrative pricing rules that were necessary in certain market conditions under the vertical demand curve construct.⁷

The Demand Curve Changes do not provide for the use of sloped demand curves in FCA 9 at the zonal level. There is simply not sufficient time for the ISO to conduct the work that is required to implement sloped demand curves at the zonal level for FCA 9.

⁴ *ISO New England Inc.*, 146 FERC ¶ 61,038 (2014) (the “January 24 Order”).

⁵ January 24 Order at P. 30.

⁶ *Id.*

⁷ The Demand Curve Changes also include a small number of other relatively minor tariff changes. These changes are not addressed further in the filing letter, but are explained in the Ethier Testimony.

Moreover, there was not sufficient time for the ISO to develop and review with stakeholders before the April 1 filing deadline all of the details that need to be addressed and incorporated in tariff changes before sloped demand curves can be implemented at the zonal level. However, as discussed in Section IV of this filing letter, the ISO does intend to work with stakeholders to complete all of the work that is required to fully implement sloped demand curves at the zonal level for FCA 10.

In support of the Demand Curve Changes, the ISO is submitting the testimony of several expert witnesses. First, Dr. Robert G. Ethier, the ISO's Vice President of Market Development, submits testimony addressing the overall rules package, including the selection of a specific demand curve shape that is appropriate for the New England region and the rules concerning inter-related issues such as the length of the "lock-in" period option for new capacity resources and the renewables exemption (the "Ethier Testimony"). Second, Dr. Samuel A. Newell, Principal, and Dr. Kathleen Spees, Senior Associate, of The Brattle Group submit testimony concerning the modeling analysis that was performed to assist in the evaluation and selection of an appropriate demand curve design (the "Newell/Spees Testimony"). Finally, the testimony of Dr. Newell and Mr. Christopher D. Ungate, Senior Principal Management Consultant, of Sargent & Lundy LLC is submitted to support the initial CONE and Net CONE values that will be used in FCA 9 (the "Newell/Ungate Testimony").

I. REQUESTED EFFECTIVE DATE

The Filing Parties request an effective date for the sloped demand curve rules of June 1, 2014 so that the rule changes related to the FCM qualification process will be in place prior to the associated deadlines for FCA 9. For example, changes related to the treatment of a significant decrease in the existing capacity of a resource (Sections III.13.1.2.2.4 and III.13.1.2.3.1) are associated with the submission of Existing Resource Qualification Packages and may impact Market Participant decisions to be made by the Existing Capacity Qualification Deadline for FCA 9, which is on June 2, 2014. Similarly, changes related to the treatment of certain resources whose summer Qualified Capacity is higher than its winter Qualified Capacity (Section III.13.1.2.2.5.2) may impact Market Participant decisions that must be made by the Existing Capacity Qualification Deadline. There are also changes related to the New Capacity Qualification Package for FCA 9, which is due on June 17, 2014. For example, Project Sponsors must decide whether to elect to lock-in Capacity Supply Obligations and Capacity Clearing Prices for up to seven years for new generating resources (Section III.13.1.1.2.2.4) or new demand resources (Section III.13.1.4.2.2.5) as part of their New Capacity Qualification Packages. Finally, by issuing an order on the sloped demand curve rules prior to the requested June 1, 2014 effective date, the Commission will provide important information to all Market Participants concerning the capacity market structure that will be in place for FCA 9.

II. DESCRIPTION OF THE FILING PARTIES; COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization (“RTO”) for New England. The ISO 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 (“NPCC”) and the North American Electric Reliability Council (“NERC”).

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 430 members. The Participants include all of the electric utilities rendering or receiving service under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, demand resource providers, developers and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission,⁸ the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, “NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff.”

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

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III. STANDARD OF REVIEW

These changes are being submitted pursuant to Section 205, which “gives a utility the right to file rates and terms for services rendered with its assets.”¹⁰ Under Section 205, the Commission “plays ‘an essentially passive and reactive role’”¹¹ whereby it “can reject [a filing] only if it finds that the changes proposed by the public utility are not ‘just and reasonable.’”¹² The Commission limits this inquiry “into whether the rates proposed by a utility are reasonable - and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs.”¹³ The changes proposed herein “need not be the only reasonable methodology, or even the most accurate.”¹⁴ As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.¹⁵

⁹ 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.

¹⁰ *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002).

¹¹ *Id.* at 10 (quoting *City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

¹² *Id.* at 9.

¹³ *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

¹⁴ *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

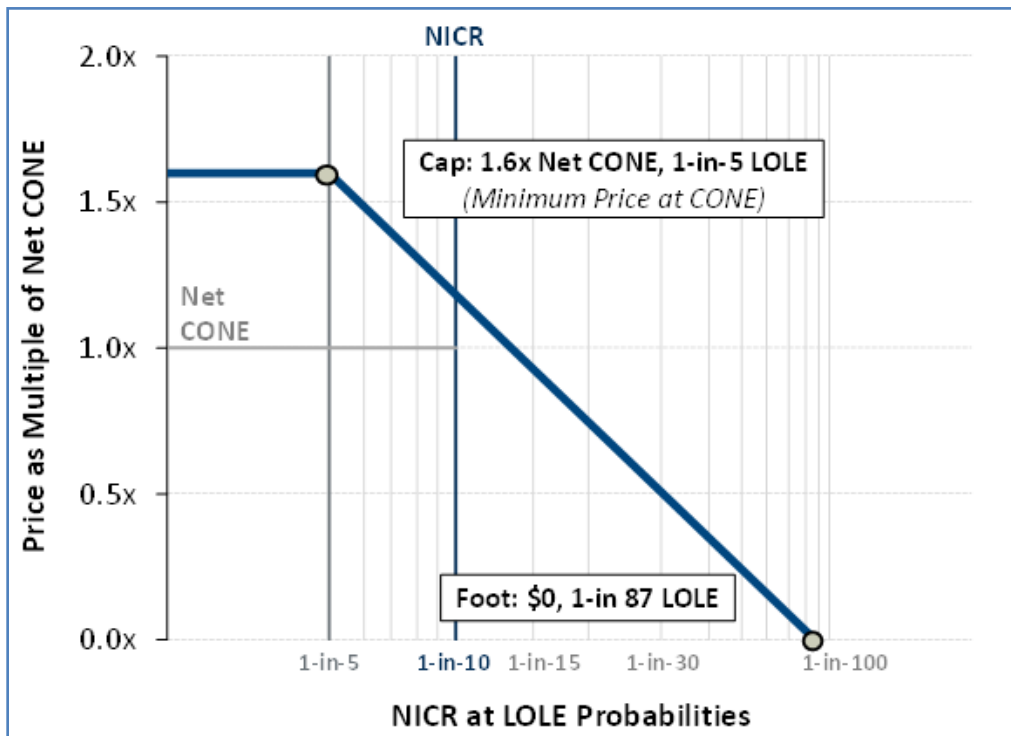
¹⁵ *Cf. Southern California Edison Co., et al*, 73 FERC ¶ 61,219 at 61,608 n.73 (1995) (“Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters.” (citing *Bethany*)).

IV. THE DEMAND CURVE CHANGES

Demand Curve Design

The Demand Curve Changes include a system-wide sloped demand curve whose shape is defined by pertinent financial and reliability parameters. These parameters include the estimated gross cost of entry for a new capacity resource (“CONE”), the estimated cost of new entry net of revenues from energy, reserve and other markets (“Net CONE”) and well-established system planning design criteria that are used to ensure resource adequacy, which are based on LOLE¹⁶ calculations. The System-Wide Capacity Demand Curve replaces the Installed Capacity Requirement (net of HQICCs)¹⁷ as the determinant of system-wide capacity demand for purposes of clearing the Forward Capacity Auction. With respect to other auction mechanics, the auctions will continue to be conducted according to the existing rules detailed in Section III.13.2 of the market rules.

The proposed demand curve is illustrated below and defined in Section III.13.2.2 of the market rules.



¹⁶ LOLE is the acronym for “Loss of Load Expectation” and refers to the probability of disconnecting non-interruptible customers due to a resource deficiency.

¹⁷ In this filing letter and the testimony, the Installed Capacity Requirement (net of HQICCs) at the 0.1 days/year LOLE value often is referred to as “NICR.”

As discussed in both the Ethier Testimony and the Newell/Spees Testimony, the design of a capacity market demand curve involves trade-offs and the balancing of a number of factors. In general, there are four factors that should be considered - reliability, price volatility, market power and robust performance.

- **Reliability** - A demand curve should be compatible with system planning criteria, such as the NPCC's "1 day in 10" design criterion regarding the probability of disconnecting firm load due to a resource deficiency.¹⁸ The sloped demand curve submitted by the Filing Parties is targeted at achieving the 0.1 days/year LOLE target¹⁹ over the long term, although the curve (like all sloped demand curves) could result in clearing more or less than the Installed Capacity Requirement (net of HQICCs) in a given auction. According to the simulation analysis conducted by The Brattle Group,²⁰ the proposed demand curve is expected to result in an average LOLE of 0.1 days/year with reserve margins 1.4% above NICR on average, and 3.1% below NICR (at the price cap) only 6.4% of the time.²¹
- **Price Volatility** - A demand curve should not result in large swings in prices in response to small movements in supply or demand. Relatively stable prices that reflect market fundamentals are more likely to encourage investor confidence and incent new entry when needed and avoid rate shocks to consumers. The proposed curve is flatter than some alternatives that were considered, reflecting the intent to avoid extreme price volatility. As shown in the Newell/Spees Testimony, the proposed demand curve should produce few outcomes at the highest and lowest ends of the pricing spectrum.²²
- **Market Power** - A well-designed demand curve should mitigate the potential for the exercise of market power. A steeper curve results in bigger swings in prices

¹⁸ Northeast Power Coordinating Council ("NPCC"), NPCC Reliability Reference Directory # 1, Design and Operation of the Bulk Power System, December 1, 2009.

¹⁹ The 0.1 days/year LOLE target reflects a single event that may be of any number of hours of duration within a day.

²⁰ Newell/Spees Testimony at p. 22 and Table 4.

²¹ The reserve margin percentages are expressed as percentages of peak load as opposed to percentages of NICR. The mean of the simulated distribution of reserve margin outcomes has to exceed NICR in order for the distribution to achieve 0.1 days/year LOLE on average because LOLE is a non-linear function of reserve margin. Low reserve margins increase the average LOLE more than high reserve margins reduce it.

²² In comparison, the existing vertical demand curve in New England recently exhibited an extreme swing in system-wide prices, going from the administrative floor price to a price just below the cap in one year. A vertical curve or an excessively steep curve produce more suboptimal results in which prices are determined administratively.

in response to relatively small changes in supply and thus is more susceptible to market power. The slope of the proposed curve is flat enough to reduce incentives to exercise market power, but steep enough to limit exposure to under- or over-procurement.²³ The potential for market power also is mitigated in conditions of extreme supply shortages because the proposed demand curve will cap prices whenever supply conditions are exceptionally short.²⁴

- **Robust Performance** - An ideal demand curve would perform well under a range of market conditions, changes in administrative parameters and administrative estimation errors. The Newell/Spees Testimony shows that potential errors in estimating Net CONE pose reliability risk for all curves considered. From a reliability perspective, the proposed curve is more robust to Net CONE estimation errors than curves that are flatter and have lower caps. It is less robust than curves that are steeper or convex and have higher caps, although such curves have higher price volatility and vulnerability to market power abuse.²⁵ Among the broad range of curves considered, the proposed curve struck the best balance among all competing objectives.

The demand curve design submitted by the Filing Parties reflects a reasonable and appropriate balancing of the four factors discussed above in the context of New England's market. There is no curve that scores perfect marks for each factor. The proposed demand curve reflects tradeoffs between the factors (for example, it is better at reducing price volatility but somewhat more vulnerable to misestimation of Net CONE). The Newell/Spees Testimony provides more detail concerning the expected performance of the proposed demand curve based on modeling analysis specific to the New England region.²⁶

Cost of New Entry

The capacity market demand curve is designed to procure sufficient capacity to maintain resource adequacy. Premised on the assumption that new entrants will set prices at true Net CONE in a long-term equilibrium state, the curve's prices are indexed to an estimated Net CONE value, with prices rising above that value if reserve margins are less than NICR + 1.4% and declining at higher reserve margins. The Newell/Spees Testimony shows that such a curve can be expected to achieve reliability objectives if the

²³ Newell/Spees Testimony at pp. 23, 49.

²⁴ For FCA 9, this price cap will be equal to \$17.728/kW-month. In the market rules, the price cap value is the same as the Forward Capacity Auction Starting Price (*see* Section III.13.2.4).

²⁵ Newell/Spees Testimony at p. 6.

²⁶ The testimony also discusses analysis conducted to determine whether the ISO's Pay for Performance mechanism, submitted and pending in Docket No. ER14-1050, is an influential factor in designing a sloped demand curve. Newell/Spees Testimony at pp. 45-48

estimated Net CONE value accurately represents the true value that new entrants would need to enter the market.²⁷

As discussed in detail in the Newell/Ungate Testimony, The Brattle Group and Sargent & Lundy conducted a detailed estimate of the cost to develop a new capacity resource in New England for FCA 9. To determine the estimated cost of new entry, three key principles and specific criteria were applied to select an appropriate “reference technology” on which to base an estimate of the cost of new entry. The three key principles were: (1) that the reference technology should be able to contribute to resource adequacy; (2) that project developers are likely to build a resource using the reference technology, and; (3) that the capacity, energy, reserve and other ancillary market revenues of the reference technology can be estimated accurately. Based on these principles and the specific criteria discussed in detail in the testimony, the reference technology used to develop the CONE²⁸ and Net CONE values for FCA 9 is a 2x1 combined cycle gas turbine (“CC”). The Newell/Ungate Testimony explains that the CC is most appropriate for the region because: (1) the CC technology is widely used throughout the country and was used for the most recent merchant generation plant that cleared the New England capacity market; (2) the prevalence of CC technology means that its cost can be estimated with a high level of confidence; (3) the inherent uncertainty in estimating CC revenues from energy, reserve and other ancillary markets is no worse, and in some cases better, than alternative technologies, and; (4) there is a low risk that basing Net CONE on the CC technology will result in capacity market under-procurement.²⁹

Estimating the total cost to build and expected revenues of a combined cycle gas turbine in New England involves numerous variables. The Newell/Ungate Testimony provides a thorough explanation of all of the cost and revenue factors that were used to develop the CONE and Net CONE values. These factors were vetted through the stakeholder review process and many factors were adjusted based on the input that was received.

As discussed in detail in the Newell/Ungate Testimony, the specific cost factors that were reviewed included capital costs as well as fixed and variable operating and maintenance (“O&M”) costs.³⁰ The capital costs that were reviewed included: (1) engineering, procurement and construction costs for major equipment, labor and

²⁷ Newell/Spees Testimony at pp. 40-43.

²⁸ In addition to being used as a base for determining Net CONE, the “gross” CONE value is used as an alternative to setting the price cap and Forward Capacity Auction Starting Price in the event that non-capacity revenues become relatively high and Net CONE, corresponding becomes relatively low (see Section III.13.2.4).

²⁹ Newell/Ungate Testimony at pp. 64-66.

³⁰ Newell/Ungate Testimony at p. 19.

materials; (2) development costs, including legal fees, gas and electric interconnections and fuel inventories, and; (3) financing fees and working capital.³¹ The O&M costs included leasing costs, property taxes, insurance and plant maintenance.³²

To calculate CONE and Net CONE values, the estimated total costs must be converted into a value that represents the capital and fixed cost recovery needed in the first year, given a reasonable long-term view of future net revenues, cost of capital and economic life. The assumptions and expert judgments used to convert the total costs to CONE and Net CONE values are explained in detail in the Newell/Ungate Testimony. The cost of entry values that are being filed herein, and are specified in Section III.13.2.4 of the revised market rules, are \$14.04/kW-month for CONE and \$11.08/kW-month for Net CONE.

The Demand Curve Changes provide for the recalculation of CONE and Net CONE values on a periodic basis (generally, every three years) coincident with the recalculation of Offer Review Trigger Prices pursuant to Section III.A.21.1.2 of the market rules. The recalculation will involve a fresh review of all cost and revenue assumptions, as well as considering the appropriate reference technology to use at that time. Whenever the 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 values are to apply. Between recalculations, CONE and Net CONE values will be updated each year and adjusted using a formula that is nearly identical to the formula for Offer Review Trigger Prices as specified in Section III.A.21.1.2(e).³³

Lock-In Extension

As discussed in the Ethier Testimony, the Demand Curve Changes include an extension from five to seven years of the period during which a Market Participant may elect to “lock-in” the capacity price for a new resource.³⁴ Perhaps more than other considerations associated with the design of a sloped demand curve, the extension of the lock-in period is closely tied to circumstances that are specific to the New England region. Under the capacity market construct that has existed for the past decade in New England, there has been a history of relatively low and administratively-determined

³¹ Newell/Ungate Testimony at pp. 30-38.

³² Newell/Ungate Testimony at pp. 38-40.

³³ As discussed in the Newell/Ungate Testimony at pp. 66-67, the estimated cost of new entry within sub-regions of New England was not substantial enough at this time to justify a separate CONE value for any sub-region. This determination will be revisited along with the overall triennial review of the CONE value.

³⁴ The tariff changes for the lock-in extension are in Sections III.13.1.1.2.2.4 (generation resources) and III.13.1.4.2.2.5 (demand resources).

prices, limited merchant entry³⁵ and the participation of some state-sponsored new resources that could reasonably create a concern among potential project developers about the potential suppression of prices³⁶ (although this concern should be alleviated by the minimum offer price rules in place since early 2013 that provide for the Internal Market Monitor to review offers associated with new capacity resources). In addition, the comparatively small size and growth rate of the New England region makes capacity prices more sensitive to new entry and other shifts in supply and demand.³⁷ Finally, New England is different from some of its neighbors in that the region is almost totally reliant on market signals to meet its reliability needs because, with the high level of disaggregation in the region, there is no backstop of vertically-integrated utilities that might otherwise step in to build capacity in the event of a shortfall.³⁸

In a competitive market, a very high price cap could be used to ensure that new entrants find it profitable to enter when new entry is needed. In the real world, however, capacity market designs must balance a number of factors, including the need to mitigate the potential for the exercise of market power.³⁹ As discussed earlier, the proposed demand curve starts with a lower price cap and has a flatter slope than some alternatives. The tradeoff is that these features mute the price signals sent to project developers. The Ethier Testimony discusses reports from potential project developers in New England which indicate that developers discount capacity market revenues beyond the current five year lock-in period and that they will continue to do so until there is a sufficient history of competitive market outcomes.⁴⁰

The extension of the lock-in period from five to seven years is intended to ensure that the overall market design, including the use of a curve that incorporates a price cap and slope that are designed to mitigate market power, provides sufficient certainty to attract new investment when needed. The relatively modest two-year extension of the lock-in period reduces the very real risk that the Demand Curve Changes might otherwise fail to attract new investment that is needed at a time when the capacity surplus that existed in the New England region for the past several years has disappeared and the possibility of further retirements of aging, inefficient resources is likely. Importantly, the ISO intends to review the need for and length of the lock-in period after there has been a series of successful auctions using the new demand curve design.

³⁵ Newell/Ungate Testimony at pp. 17, 43-44.

³⁶ *Id.* at pp. 43-44.

³⁷ *Id.*

³⁸ Ethier Testimony at p. 31.

³⁹ The need to ensure that a demand curve design sufficiently addresses the potential exercise of market power was highlighted by the results of FCA 8, which resulted in administrative prices due to a lack of sufficient competition.

⁴⁰ Ethier Testimony at pp. 31-32.

Renewables Exemption

The Demand Curve Changes include a limited and narrow exemption from the capacity market's buyer-side mitigation rules for Renewable Technology Resources that are built to advance state policy objectives.⁴¹ The exemption will permit no more than 200 MW of capacity from Renewable Technology Resources to participate in each Forward Capacity Auction⁴² without being constrained by the requirement to submit offer prices above the New Resource Offer Floor Price.⁴³ As provided in Section III.13.1.1.1.7 of the market rules, eligibility for Renewable Technology Resource treatment is limited to new resources that qualify under state renewable or alternative energy portfolio standards (or, in states without a portfolio standard, qualify under that state's renewable energy goals as a renewable resource), as in effect on January 1, 2014, and that are geographically located in the state in which they qualify.

The renewables exemption included in the Demand Curve Changes is a reasonable means of accommodating legitimate state policies that favor renewable resources and that are not intended to suppress market-clearing prices, while being sufficiently limited to alleviate design concerns.⁴⁴ The exemption recognizes that certain market participants have a legitimate need to satisfy their renewable portfolio standard obligations and ensures that up to 200 MW of Renewable Technology Resources has the opportunity to clear in each capacity auction and be available to satisfy renewable portfolio standards when these resources otherwise might be prevented from clearing by the offer floor price. Importantly, compared to the alternative of clearing the capacity market to satisfy NCR with non-renewable resources and then building renewable resources outside the market to satisfy renewable portfolio standards, the exemption does not require consumers to pay for additional capacity that exceeds the requirements of the demand curve.

As explained in the Ethier Testimony, while allowing legitimate state policies to be furthered without imposing additional costs on consumers, the renewables exemption is limited so as to minimize potential concerns about price suppression.⁴⁵ The 200 MW

⁴¹ Ethier Testimony, Section VII, at pp. 37-42.

⁴² See Section III.13.1.1.2.10. The rules prorate any amount of Renewable Technology Resources greater than 200 MW in a single auction. Any prorated amount is eligible for the renewables exemption in future auctions. Further, the rules allow any unused portion of the 200 MW cap to carry forward for up to two years. For example, up to 600 MW of Renewable Technology Resources could clear a future auction if no Renewable Technology Resources cleared in the prior two auctions.

⁴³ See Section III.13.2.3.2 (a)(v).

⁴⁴ Ethier Testimony at pp. 38-39.

⁴⁵ Ethier Testimony at pp. 40-42.

limit on the amount of Renewable Technology Resources that may clear in an auction is intended to ameliorate price suppression concerns given that the combination of load growth and retirement of existing resources would have to be less than 200 MW in order to result in suppression of prices when the market is at or near equilibrium. In addition, the use of a sloped demand curve itself limits any concerns about price suppression since the potential price impact of a low-priced renewable resource is far less under a sloped demand curve than under the vertical demand curve that is currently used in New England's capacity market since small changes in quantity have a much smaller impact on price.

Elimination of System-Wide Administrative Pricing Rules

The Demand Curve Changes eliminate the use of the administrative pricing provisions at the system-wide level that were included in the existing provisions of Section III.13.2.8. As discussed in the Newell/Spees Testimony, a sloping demand curve more effectively and efficiently addresses the performance concerns associated with a vertical demand curve which the administrative rules were originally implemented to mitigate.⁴⁶ In place of a vertical demand curve and administrative rules, the new System-Wide Capacity Demand Curve will be used to determine prices and the quantity cleared at the system-wide level for Forward Capacity Auctions.

Zonal Demand Curves

As discussed earlier, the ISO is not able to develop and implement sloped demand curves at the zonal level for FCA 9. However, the ISO intends to work with stakeholders to develop the necessary rules and implement sloped demand curves at the zonal level for FCA 10.⁴⁷ In the meantime, the Demand Curve Changes do update the administrative prices that could apply in FCA 9 at the zonal level in the event of either Inadequate Supply or Insufficient Competition. If either of these conditions are triggered in FCA 9 at the zonal level, the payment rate for existing resources in that zone will be set using the current administrative formulas but substituting the current fixed price of \$7.025/kW-month with the higher of Net CONE (\$11.08/kW-month) or the Capacity Clearing Price for the Rest-of-Pool Capacity Zone.⁴⁸ These values are appropriate because the best alternative to a competitively-determined price in an import-constrained zone is the "target" long-term price based on estimated Net CONE or, if the system-wide price is higher, the Capacity Clearing Price for the Rest-of-Pool Capacity Zone.

⁴⁶ Newell/Spees Testimony at pp. 26-27.

⁴⁷ Some stakeholders have expressed interest in revisiting, prior to the triennial recalculation, whether a different CONE or Net CONE value than the system-wide value should be used in a sub-region.

⁴⁸ See Sections III.13.2.8.1 and III.13.2.8.2.

Other Future Rule Changes

In addition to addressing the use of sloped demand curves at the zonal level for FCA 10, the ISO also is planning to work with stakeholders to address several other issues that will require further market rule changes.

The ISO already has started working with the NEPOOL Reliability Committee to develop changes to Section III.12 of Market Rule 1 to reflect the need to calculate Installed Capacity Requirement quantities at the additional LOLE values that define points on the System-Wide Capacity Demand Curve pursuant to Section III.13.2.2. The ISO expects that these additional Installed Capacity Requirement values will be filed with the Commission as part of the existing Installed Capacity Requirements filing that is submitted at least 90 days prior to each Forward Capacity Auction pursuant to Section III.12.3. The changes to Section III.12 likely will be filed with the Commission within a few months.

The ISO also will be working with the NEPOOL Markets Committee to address how reconfiguration auctions will work for Capacity Commitment Periods associated with FCA 9 and later auctions. While all issues related to the operation of reconfiguration auctions under the sloped demand curve construct are being considered and addressed, the Demand Curve Changes make clear that the existing reconfiguration auction rules that are in tariff today only apply to Capacity Commitment Periods that begin prior to June 1, 2018.⁴⁹

Monitoring and Review

The ISO, its internal and external market monitors and stakeholders will all be monitoring and reviewing the performance of the capacity market under the new sloped demand curve construct. If auction results or other events indicate that changes to the demand curve design are warranted, the ISO will work with stakeholders to address these issues. In exigent circumstances, issues could be addressed immediately by the ISO pursuant to its authority under Section 11 of the Participants Agreement.

V. STAKEHOLDER PROCESS

At its March 19, 2014 meeting, the NEPOOL Markets Committee voted to recommend that the NEPOOL Participants Committee support the Demand Curve Changes by a vote of 74.08%.⁵⁰ At its March 21, 2014 meeting, the Participants Committee voted to support the Demand Curve Changes by a vote of 69.53%.⁵¹

⁴⁹ See Section III.13.4.

⁵⁰ The individual Sector votes of the NEPOOL Markets Committee were Generation (2.86% in favor, 14.31% opposed, 3 abstentions), Transmission (17.17% in favor, 0% opposed, 1 abstention), Supplier (8.89% in favor, 8.28% opposed, 7.7 abstentions), Alternative Resources

(continued...)

The New England States Committee on Electricity, representing the unanimous position of all six states, also supported the ultimate package of demand curve changes proposed by the ISO and supported by NEPOOL. NESCOE noted that while the revisions included aspects that would not be acceptable on a stand-alone basis, the package of changes as a whole reflects a fair and balanced proposal.

VI. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the sloped demand curve rule changes do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations.⁵² Notwithstanding its 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;⁵³
- Clean ISO Tariff sections reflecting the revision submitted in this filing;
- Testimony of Dr. Robert G. Ethier, the ISO's Vice President of Market Development, sponsored solely by the ISO;

(...continued)

(10.83% in favor, 3.34% opposed), Publicly Owned Entity (17.17% in favor, 0% opposed, 42 abstentions), and End User (17.17% in favor, 0% opposed, 1 abstention).

⁵¹ See NEPOOL Participants Committee Vote Tabulation, attached hereto.

⁵² 18 C.F.R. § 35.13 (2011).

⁵³ The revisions to the ISO Tariff filed in this proceeding have been marked against a base version of the Forward Capacity Market rules that reflects the ISO's Pay for Performance proposal that was filed as one of two proposals submitted in the "jump ball" proceeding that is currently pending before the Commission in Docket No. ER14-1050. NEPOOL filed an alternative Performance Incentives proposal in Docket No. ER14-1050. The use of a base version of the ISO Tariff reflecting the ISO's proposal in Docket No. ER14-1050 is expressly without prejudice to the outcome of the "jump ball" proceeding. As necessary, the ISO Tariff revisions submitted in this proceeding will be promptly revised to reflect the outcome of the proceeding in Docket No. ER14-1050.

- Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees of The Brattle Group, sponsored solely by the ISO;
- Testimony of Dr. Samuel A. Newell of The Brattle Group and Mr. Christopher D. Ungate of Sargent & Lundy LLC, sponsored solely by the ISO;
- Curriculum Vitae for ISO-sponsored testimony;
- NEPOOL Participants Committee Vote Tabulation;
- 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 1, 2014.

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

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

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.

VII. CONCLUSION

For the reasons discussed in this transmittal letter, the Filing Parties request that the Commission accept the sloped demand curve rule changes to become effective on June 1, 2014.

Respectfully submitted,

ISO NEW ENGLAND INC.

**NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE**

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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.

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

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.

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 Capacity Price Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.8 of Market Rule 1.

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

Alternative Technologies Regulation Pilot Program is the pilot described in Appendix J to Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Average Hourly Output is either: (i) the sum of the Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure

consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

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

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 the day); (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, 2017, 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.

Cancellation Fee is defined in Section III.1.10.2(d).

Cancelled Start Credit is a credit calculated pursuant to Section III.F.2.5 of Appendix F to Market Rule 1 as the NCPC Credit due to each Market Participant for pool-scheduled generating Resources that were scheduled by the ISO to start after the close of the Day-Ahead Energy Market and that were cancelled by the ISO prior to their assigned commitment time.

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 January 17, 2014.

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

Capacity Carried Forward Due to Rationing is described in Section III.13.2.7.8.2.1(c)(b)(ii) of Market Rule 1.

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 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 January 17, 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 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-to-Service Ratio is defined in Section III.3.2.2(h) of Market Rule 1.

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

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

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

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

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

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

Carried Forward Excess Capacity is calculated as described in Section III.13.2.7.8.2.1(c) of Market Rule 1.

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.

Cold Weather Conditions means any calendar day when that day's Effective Temperatures are forecast to be equal to or less than zero degrees Fahrenheit for any single on-peak hour and that day's total Effective Heating Degree Days are forecast to be greater than or equal to 65.

Cold Weather Event means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than or equal to 0 MW for an Operating Day. Cold Weather Events are declared by 1100 two days prior to the Operating Day. A Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists, until such time that the ISO declares a Cold Weather Event.

Cold Weather Warning means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than 1,000 MW. In addition, a Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists for days not yet declared as a Cold Weather Event.

Cold Weather Watch means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin greater than or equal to 1,000 MW.

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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Cost of New Entry (CONE) is the ~~value that was estimated cost of new entry (\$/kW-month) for a capacity resource that is~~ determined by the ISO for each Forward Capacity Auction pursuant to ~~the provisions of Section III.13.2.4 of Market Rule 1 in effect at the time of that auction.~~

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

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

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

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

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

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

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

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

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

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

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

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

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

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2017, 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, 2017.

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 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, 2017, 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 the electricity consumption of an individual end-use customer at a Retail Delivery Point or the aggregated electricity consumption of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2.

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 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, 2017.

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 Resource's or contract's Supply Offer or Demand Bid 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 level of each generating Resource and each Dispatchable Asset Related Demand and each Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

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

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

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

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

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

Distributed Generation means generation resources directly connected to end-use customer load and located behind the end-use customer's meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

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

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

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at or 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 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 the maximum of the following values: (i) the Emergency Minimum Limit; (ii) a level supported by environmental and/or operating permit restrictions; or (iii) a level that addresses any significant economic penalties associated with operating at lower levels that can not be adequately represented by three part bidding (Start-Up Fee, No-Load Fee and incremental energy price). In no event shall the Economic Minimum Limit submitted as part of a generating unit's Offer Data be higher than the generation level at which a generating unit's incremental heat rate is minimized (i.e., transitioning from decreasing as output increases to increasing as output increases) except that a Self-Scheduled Resource may modify its Economic Minimum Limit on an hourly basis, as part of its Supply Offer, in order to indicate the desired level of Self-Scheduled MWs.

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

EFT is electronic funds transfer.

Effective Heating Degree Days is equal to $68 - (\text{average of max and min Effective Temperature of the day})$.

Effective Temperature is equal to dry bulb temperature – $[\text{windspeed} \times (65 - \text{dry bulb temp}) / 100]$.

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.5 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

Elective Transmission Upgrade Applicant is defined in Section II.47.5 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, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II 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 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.

Exempt Real-Time Generation Obligation means that portion of a Market Participant's Real-Time Generation Obligation that is not included in the calculation of Minimum Generation Emergency Credits pursuant to Appendix F of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

External 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.

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 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) time to start does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Governance Participant is defined in the Participants Agreement.

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

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

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

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

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

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian

border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

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

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

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

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

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

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

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

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

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 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Agreement is the “Large Generator Interconnection Agreement” or the “Small Generator Interconnection Agreement” pursuant to Schedules 22 and 23 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 and Attachment 1 to Schedule 23 of the OATT.

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

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

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

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

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

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

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load

Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

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

Internal 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 or Demand Bids 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 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 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, 2017, 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, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

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

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

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

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

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

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

LSE means load serving entity.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or

exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

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

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

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

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

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

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

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

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

Measure Life is the estimated time a Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the Demand Reduction Value of the Demand Resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the Demand Reduction Value for an Existing Demand Resource is not overstated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

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

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

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

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

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

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

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

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

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

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

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

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

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

Minimum 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 Charge means the charge used to allocate the cost of Minimum Generation Emergency Credits. Minimum Generation Emergency Charges are discussed in Appendix F of Market Rule 1.

Minimum Generation Emergency Credits are credits calculated pursuant to Appendix F of Market Rule 1 to compensate certain generating Resources for operation in excess of their Economic Minimum Limits during a Minimum Generation Emergency.

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 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 MWs.

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 MWs.

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

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

MUI is the market user interface.

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

MW is megawatt.

MWh is megawatt-hour.

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

NCPC Charge means the charges to Market Participants as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

NCPC Credit means the payment made to a Resource as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

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.

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 Generator Asset is the Generator Asset registered in the energy market at the same Retail Delivery Point as a Demand Response Asset with Distributed Generation capable of delivering Net Supply.

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

Network Customer is a Transmission Customer receiving RNS or LNS.

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, as described in Section III.13.2.3.2 of Market Rule 1.

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.

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

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

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

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

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

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

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

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

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

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission.

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, 2017, 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, 2017.

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 a Supply Offer value between 0 and the CLAIM10 of a Resource that represents the amount of TMNSR available from the Resource.

Offered CLAIM30 is a Supply Offer value between 0 and the CLAIM30 of a Resource that represents the amount of offline TMOR available from the Resource.

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

On-Peak Demand Resource is a type of Demand Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

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

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

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

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

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

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

Operations Date is February 1, 2005.

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

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

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as

adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability.

Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

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

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 Credit is calculated pursuant to Section III.F.2.6.2 of Appendix F to Market Rule 1.

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 or New Demand Resource participate in the Forward Capacity Market, as described in Section III.13.

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

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

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.

Queue Position has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 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 Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

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, 2017, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2017.

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 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 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 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 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.5.6.1 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 generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

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 Capability (REGCAP) means the amount of Regulation capability available on a Market Participant's Resource as calculated by the ISO based upon that Resource's Automatic Response Rate and the available regulating range as specified in ISO New England Manual 11 – Market Operations.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.

Regulation Rank Price is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

Regulation Requirement is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

Regulation Service Credit is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

Regulation Service Megawatts are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

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 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, 2017, 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 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, 2017, a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the

Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

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 and/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. 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 the greater of: (i) the Resource's Economic Minimum Limit; or (ii) the Resource's Minimum Consumption Limit; or (iii)

for a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.

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.

Seven-Day Forecast has the meaning specified in Section III.H.3.3(a).

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).

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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

Start-Up Fee is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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

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

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

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. The daily bid Blocks in the price-based Real-Time offer/bid will be multiplied by the number of hours in the day 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, or Schedule 23 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 a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

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 a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, and is provided by generating units and Dispatchable Asset Related Demand pumps 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 a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England

Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

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.

Time-on-Regulation Credit is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

Time-on-Regulation Megawatts is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

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 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.

Table of Contents

III.1	Market Operations	
III.1.1	Introduction.	
III.1.2	[Reserved.]	
III.1.3	Definitions.	
III.1.3.1	[Reserved.]	
III.1.3.2	[Reserved.]	
III.1.3.3	[Reserved.]	
III.1.4	Requirements for Certain Transactions.	
III.1.4.1	ISO Settlement of Certain Transactions.	
III.1.4.2	Transactions Subject to Requirements of Section III.1.4.	
III.1.4.3	Requirements for Section III.1.4 Conforming Transactions.	
III.1.5	Resource Auditing.	
III.1.5.1.	Claimed Capability Audits.	
III.1.5.1.1.	General Audit Requirements.	
III.1.5.1.2.	Establish Claimed Capability Audit.	
III.1.5.1.3.	Seasonal Claimed Capability Audits.	
III.1.5.1.4.	ISO-Initiated Claimed Capability Audits.	
III.1.5.2.	ISO-Initiated Parameter Auditing.	
III.1.6	[Reserved.]	
III.1.6.1	[Reserved.]	
III.1.6.2	[Reserved.]	
III.1.6.3	[Reserved.]	
III.1.6.4	ISO New England Manuals and ISO New England Administrative Procedures.	
III.1.7	General.	
III.1.7.1	Provision of Market Data to the Commission.	
III.1.7.2	[Reserved.]	

III.1.7.3	Agents.
III.1.7.4	[Reserved.]
III.1.7.5	[Reserved.]
III.1.7.6	Scheduling and Dispatching.
III.1.7.7	Energy Pricing.
III.1.7.8	Market Participant Resources.
III.1.7.9	Real-Time Reserve Prices.
III.1.7.10	Other Transactions.
III.1.7.11	Seasonal Claimed Capability of A Generating Capacity Resource.
III.1.7.12	[Reserved.]
III.1.7.13	[Reserved.]
III.1.7.14	[Reserved.]
III.1.7.15	[Reserved.]
III.1.7.16	[Reserved.]
III.1.7.17	Operating Reserve.
III.1.7.18	Regulation.
III.1.7.19	Ramping.
III.1.7.19A	Real-Time Reserve.
III.1.7.20	Information and Operating Requirements.
III.1.8	[Reserved.]
III.1.9	Pre-scheduling.
III.1.9.1	[Reserved.]
III.1.9.2	[Reserved.]
III.1.9.3	[Reserved.]
III.1.9.4	[Reserved.]
III.1.9.5	[Reserved.]
III.1.9.6	[Reserved.]
III.1.9.7	Market Participant Responsibilities.

III.1.9.8	[Reserved.]
III.1.10	Scheduling.
III.1.10.1	General.
III.1.10.1A	Day Ahead Energy Market Scheduling.
III.1.10.2	Pool Scheduled Resources.
III.1.10.3	Self-Scheduled Resources.
III.1.10.4	[Reserved.]
III.1.10.5	External Resources.
III.1.10.6	Dispatchable Asset Related Demand Resources.
III.1.10.7	External Transactions.
III.1.10.8	ISO Responsibilities.
III.1.10.9	Hourly Scheduling.
III.1.11	Dispatch.
III.1.11.1	Resource Output.
III.1.11.2	Operating Basis.
III.1.11.3	Pool-dispatched Resources.
III.1.11.4	Emergency Condition.
III.1.11.5	Regulation.
III.1.11.6	[Reserved.]
III.1.12	Dynamic Scheduling.
III.2	LMPs and Real-Time Reserve Clearing Prices Calculation
III.2.1	Introduction.
III.2.2	General.
III.2.3	Determination of System Conditions Using the State Estimator.
III.2.4	Determination of Energy Offers Used in Calculating Real-Time Prices and Real-Time Reserve Clearing Prices.
III.2.5	Calculation of Real-Time Nodal Prices.
III.2.6	Calculation of Day-Ahead Nodal Prices.

- III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.
- III.2.7A Calculation of Real-Time Reserve Clearing Prices.
- III.2.8 Hubs and Hub Prices.
- III.2.9A Final Real-Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.
- III.2.9B Final Day-Ahead Energy Market Results.
- III.3 Accounting And Billing
 - III.3.1 Introduction.
 - III.3.2 Market Participants.
 - III.3.2.1 ISO Energy Market.
 - III.3.2.2 Regulation.
 - III.3.2.3 NCPC Credits.
 - III.3.2.4 Transmission Congestion.
 - III.3.2.5 [Reserved.]
 - III.3.2.6 Emergency Energy.
 - III.3.2.6A New Brunswick Security Energy.
 - III.3.2.7 Billing.
 - III.3.3 [Reserved.]
 - III.3.4 Non-Market Participant Transmission Customers.
 - III.3.4.1 Transmission Congestion.
 - III.3.4.2 Transmission Losses.
 - III.3.4.3 Billing.
 - III.3.5 [Reserved.]
 - III.3.6 Data Reconciliation.
 - III.3.6.1 Data Correction Billing.
 - III.3.6.2 Eligible Data.
 - III.3.6.3 Data Revisions.
 - III.3.6.4 Meter Corrections Between Control Areas.

- III.3.6.5 Meter Correction Data.
 - III.3.7 Eligibility for Billing Adjustments.
 - III.3.8 Correction of Meter Data Errors.
 - III.4 Rate Table
 - III.4.1 Offered Price Rates.
 - III.4.2 [Reserved.]
 - III.4.3 Emergency Energy Transaction.
 - III.5 Transmission Congestion Revenue & Credits Calculation
 - III.5.1 Non-Market Participant Transmission Congestion Cost Calculation
 - III.5.1.1 Calculation by ISO.
 - III.5.1.2 General.
 - III.5.1.3 [Reserved.]
 - III.5.1.4 Non-Market Participant Transmission Customer Calculation.
 - III.5.2 Transmission Congestion Credit Calculation.
 - III.5.2.1 Eligibility.
 - III.5.2.2 Financial Transmission Rights.
 - III.5.2.3 [Reserved.]
 - III.5.2.4 Target Allocation to FTR Holders.
 - III.5.2.5 Calculation of Transmission Congestion Credits.
 - III.5.2.6 Distribution of Excess Congestion Revenue.
 - III.6 Local Second Contingency Protection Resources
 - III.6.1 [Reserved.]
 - III.6.2 Day-Ahead and Real-Time Energy Market.
 - III.6.2.1 Special Constraint Resources.
 - III.6.3 [Reserved.]
 - III.6.4 Local Second Contingency Protection Resource NCPC Charges.
 - III.6.4.1 [Reserved.]
 - III.6.4.2 [Reserved.]

III.6.4.3 Calculation of Local Second Contingency Protection Resource
NCPC Payments.

III.7 Financial Transmission Rights Auctions

III.7.1 Auctions of Financial Transmission Rights.

III.7.1.1 Auction Period and Scope of Auctions.

III.7.1.2 FTR Auctions Assumptions.

III.7.2 Financial Transmission Rights Characteristics.

III.7.2.1 Reconfiguration of Financial Transmission Rights.

III.7.2.2 Specified Locations.

III.7.2.3 Transmission Congestion Revenues.

III.7.2.4 [Reserved.]

III.7.3 Auction Procedures.

III.7.3.1 Role of the ISO.

III.7.3.2 [Reserved.]

III.7.3.3 [Reserved.]

III.7.3.4 On-Peak and Off-Peak Periods.

III.7.3.5 Offers and Bids.

III.7.3.6 Determination of Winning Bids and Clearing Price.

III.7.3.7 Announcement of Winners and Prices.

III.7.3.8 Auction Settlements.

III.7.3.9 Allocation of Auction Revenues.

III.7.3.10 Simultaneous Feasibility.

III.7.3.11 [Reserved.]

III.7.3.12 Financial Transmission Rights in the Form of Options.

III.8A. Demand Response Baselines

III.8A.1. Establishing the Initial Demand Response Baseline.

III.8A.2. Establishing the Demand Response Baseline for the Next Day.

III.8A.3. Determining if Meter Data From the Present Day is Used in the Demand
Response Baseline for the Next Day.

III.8A.4. Baseline Adjustment.

III.8A.4.1. Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets Without Generation or From Real-Time Emergency Generation Assets Without Additional Generation.

III.8A.4.2. Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets with Generation or From Real-Time Emergency Generation Assets With Additional Generation.

III.8A.4.3. Baseline Adjustment for Real-Time Demand Reductions Produced By Directly Metered Generation.

III.8B. Demand Response Baselines.

III.8B.1. Demand Response Baseline Calculations,

III.8B.1.1. Demand Response Baseline Real-Time Emergency Generation Asset Adjustment.

III.8B.2. Establishing an Initial Demand Response Baseline.

III.8B.3. Establishing a Demand Response Baseline for the Next Day.

III.8B.4. Determining if Meter Data from the Present Day is Used in the Demand Response Baseline for the Next Day of the Same Day Type.

III.8B.5. Baseline Adjustment.

III.9 Forward Reserve Market

III.9.1 Forward Reserve Market Timing.

III.9.2 Forward Reserve Market Reserve Requirements.

III.9.2.1 Forward Reserve Market Minimum Reserve Requirements.

III.9.2.2 Locational Reserve Requirements for Reserve Zones.

III.9.3 Forward Reserve Auction Offers.

III.9.4 Forward Reserve Auction Clearing and Forward Reserve Clearing Prices.

III.9.4.1 Forward Reserve Clearing Price and Forward Reserve Obligation Publication and Correction.

III.9.5. Forward Reserve Resources

III.9.5.1 Assignment of Forward Reserve MWs to Forward Reserve Resources.

III.9.5.2 Forward Reserve Resource Eligibility Requirements.

- III.9.5.3 Resource CLAIM10 and CLAIM30 Values.
- III.9.5.3.1. Calculating Resource CLAIM10 and CLAIM30 Values.
- III.9.5.3.2. CLAIM10 and CLAIM 30 Audits.
- III.9.5.3.3. CLAIM10 and CLAIM30 Performance Factors.
- III.9.5.3.4. Performance Factor Cure.
- III.9.6 Delivery of Reserve.
 - III.9.6.1 Dispatch and Energy Bidding of Reserve.
 - III.9.6.2 Forward Reserve Threshold Prices.
 - III.9.6.3 Monitoring of Forward Reserve Resources.
 - III.9.6.4 Forward Reserve Qualifying Megawatts.
 - III.9.6.5 Delivery Accounting.
- III.9.7 Consequences of Delivery Failure.
 - III.9.7.1 Real-Time Failure-to-Reserve.
 - III.9.7.2 Failure-to-Activate Penalties.
 - III.9.7.3 Known Performance Limitations.
- III.9.8 Forward Reserve Credits.
- III.9.9 Forward Reserve Charges.
 - III.9.9.1 Forward Reserve Credits Associated with System Reserve Requirements.
 - III.9.9.2 Adjusting Forward Reserve Credits for System Requirements.
 - III.9.9.3 Allocating Forward Reserve Credits for System Requirements.
 - III.9.9.4 Allocating Remaining Forward Reserve Credits.
 - III.9.9.4.1 Allocation Criteria for Remaining Forward Reserve Credits.
- III.10 Real-Time Reserve
 - III.10.1 Provision of Operating Reserve in Real-Time.
 - III.10.1.1 Real-Time Reserve Designation.
 - III.10.2 Real-Time Reserve Credits.
 - III.10.3 Real-Time Reserve Charges.
 - III.10.4 Forward Reserve Obligation Charges.

- III.10.4.1 Forward Reserve Obligation Charge Megawatts for Forward Reserve Resources.
 - III.10.4.2 Forward Reserve Obligation Charge Megawatts.
 - III.10.4.3 Forward Reserve Obligation Charge.
- III.11 Gap RFPs For Reliability Purposes
 - III.11.1 Request For Proposals for Load Response and Supplemental Generation Resources for Reliability Purposes.
- III.12 Calculation of Capacity Requirements
 - III.12.1 Installed Capacity Requirement.
 - III.12.2 Local Sourcing Requirements and Maximum Capacity Limits.
 - III.12.2.1 Calculation of Local Sourcing Requirements for Import-Constrained Load Zones.
 - III.12.2.1.1 Local Reserve Adequacy Requirement.
 - III.12.2.1.2 Transmission Security Analysis Requirement.
 - III.12.2.2 Calculation of Maximum Capacity Limit for Export-Constrained Load Zones.
 - III.12.3 Consultation and Filing of Capacity Requirements.
 - III.12.4 Capacity Zones.
 - III.12.5 Transmission Interface Limits.
 - III.12.6 Modeling Assumptions for Determining the Network Model.
 - III.12.6.1 Process for Establishing the Network Model.
 - III.12.6.2 Initial Threshold to be Considered In-Service.
 - III.12.6.3 Evaluation Criteria.
 - III.12.7 Resource Modeling Assumptions.
 - III.12.7.1 Proxy Units.
 - III.12.7.2 Capacity.
 - III.12.7.2.1 [Reserved.]
 - III.12.7.3 Resource Availability.
 - III.12.7.4 Load and Capacity Relief.
 - III.12.8 Load Modeling Assumptions.

III.12.9	Tie Benefits.
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.
III.12.9.1.2.	Tie Benefits Calculation.
III.12.9.1.3.	Adjustments to Account for Transmission Import Capability and Capacity Imports.
III.12.9.2	Modeling Assumptions and Procedures for the Tie Benefits Calculation.
III.12.9.2.1.	Assumptions Regarding System Conditions.
III.12.9.2.2.	Modeling Internal Transmission Constraints in New England.
III.12.9.2.3.	Modeling Transmission Constraints in Neighboring Control Areas.
III.12.9.2.4.	Other Modeling Assumptions.
III.12.9.2.5.	Procedures for Adding or Removing Capacity from Control Areas to Meet the 0.1 Days Per Year LOLE Standard.
III.12.9.3.	Calculating Total Tie Benefits.
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.
III.12.9.4.2.	Pro Ration Based on Total Tie Benefits.
III.12.9.5.	Calculating Tie Benefits for Individual Ties.
III.12.9.5.1.	Initial Calculation of Tie Benefits for an Individual Interconnection or Group of Interconnections.
III.12.9.5.2.	Pro Ration Based on Total Tie Benefits.
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.
III.12.9.6.2.	Changes in the Import Capability of Interconnections with Neighboring Control Areas.
III.12.9.7.	Tie Benefits Over the HQ Phase I/II HVDC-TF.

- 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.
- III.13 Forward Capacity Market
 - III.13.1 Forward Capacity Auction Qualification.
 - III.13.1.1 New Generating Capacity Resources.
 - III.13.1.1.1 Definition of New Generating Capacity Resource.
 - III.13.1.1.1.1 Resources Never Previously Counted as Capacity.
 - III.13.1.1.1.2 Resources Previously Counted as Capacity.
 - III.13.1.1.1.3 Incremental Capacity of Resources Previously Counted as Capacity.
 - III.13.1.1.1.4 De-rated Capacity of Resources Previously Counted as Capacity.
 - III.13.1.1.1.5 Treatment of Resources that are Partially New and Partially Existing.
 - III.13.1.1.1.6 Treatment of Deactivated and Retired Units.
 - III.13.1.1.1.7 Renewable Technology Resources.
 - III.13.1.1.2 Qualification Process for New Generating Capacity Resources.
 - III.13.1.1.2.1 New Capacity Show of Interest Form.
 - III.13.1.1.2.2 New Capacity Qualification Package.
 - III.13.1.1.2.2.1 Site Control.
 - III.13.1.1.2.2.2 Critical Path Schedule.
 - III.13.1.1.2.2.3 Offer Information.
 - III.13.1.1.2.2.4 Capacity Commitment Period Election.
 - III.13.1.1.2.2.5 Additional Requirements for Resources Previously Listed as Capacity.
 - III.13.1.1.2.2.6 Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.
 - III.13.1.1.2.3 Initial Interconnection Analysis.
 - III.13.1.1.2.4 Evaluation of New Capacity Qualification Package.
 - III.13.1.1.2.5 Qualified Capacity for New Generating Capacity Resources.

- III.13.1.1.2.5.1 New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.
- III.13.1.1.2.5.2 [Reserved.]
- III.13.1.1.2.5.3 New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.
- III.13.1.1.2.5.4 New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.
- III.13.1.1.2.6 [Reserved.]
- III.13.1.1.2.7 Opportunity to Consult with Project Sponsor.
- III.13.1.1.2.8 Qualification Determination Notification for New Generating Capacity Resources.
- III.13.1.1.2.9 Renewable Technology Resource Election.
- III.13.1.1.2.10 Determination of Renewable Technology Resource Qualified Capacity.
- III.13.1.2 Existing Generating Capacity Resources.
 - III.13.1.2.1 Definition of Existing Generating Capacity Resource.
 - III.13.1.2.2 Qualified Capacity for Existing Generating Capacity Resources.
 - III.13.1.2.2.1 Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.
 - III.13.1.2.2.1.1 Summer Qualified Capacity.
 - III.13.1.2.2.1.2 Winter Qualified Capacity.
 - III.13.1.2.2.2 Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.
 - III.13.1.2.2.2.1 Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.
 - III.13.1.2.2.2.2 Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.
 - III.13.1.2.2.3 Qualified Capacity Adjustment for Partially New and Partially Existing Resources.
 - III.13.1.2.2.4 Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.
 - III.13.1.2.2.5 Adjustment for Certain Significant Increases in Capacity.
 - III.13.1.2.2.5.1 [Reserved.]

III.13.1.2.2.5.2	Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.
III.13.1.2.3	Qualification Process for Existing Generating Capacity Resources.
III.13.1.2.3.1	Existing Capacity Qualification Package.
III.13.1.2.3.1.A	Dynamic De-List Bid Threshold.
III.13.1.2.3.1.1	Static De-List Bids.
III.13.1.2.3.1.2	Permanent De-List Bids.
III.13.1.2.3.1.3	Export Bids.
III.13.1.2.3.1.4	Administrative Export De-List Bids.
III.13.1.2.3.1.5	Non-Price Retirement Request.
III.13.1.2.3.1.5.1	Description of Non-Price Retirement Request.
III.13.1.2.3.1.5.2	Timing Requirements.
III.13.1.2.3.1.5.3	Reliability Review of Non-Price Retirement Requests.
III.13.1.2.3.1.5.4	Obligation to Retire.
III.13.1.2.3.1.6	Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.
III.13.1.2.3.1.6.1	Submission of Cost Data.
III 13.1.2.3.1.6.2	[Reserved.]
III 13.1.2.3.1.6.3	Internal Market Monitor Review.
III.13.1.2.3.2	Review by Internal Market Monitor of Bids Received from Existing Generating Capacity Resources.
III.13.1.2.3.2.1	Static De-List Bids, Export Bids Above the Dynamic De-List Bid Threshold, and Permanent De-List Bids Above the Dynamic De-List Bid Threshold.
III.13.1.2.3.2.1.1	Internal Market Monitor Review of De-List Bids.
III.13.1.2.3.2.1.1.1.	Review of Permanent De-List Bids and Export Bids.
III.13.1.2.3.2.1.1.2.	Review of Static De-List Bids.
III.13.1.2.3.2.1.2	Net Going Forward Costs.
III.13.1.2.3.2.1.3	Expected Capacity Performance Payments.

III.13.1.2.3.2.1.4	Risk Premium.
III.13.1.2.3.2.1.5	Opportunity Costs.
III.13.1.2.3.2.2	[Reserved.]
III.13.1.2.3.2.3	Administrative Export De-List Bids.
III.13.1.2.3.2.4	Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.
III.13.1.2.3.2.5	Incremental Capital Expenditure Recovery Schedule.
III.13.1.2.4	Qualification Determination Notification for Existing Capacity.
III.13.1.2.5	Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.
III.13.1.3	Import Capacity.
III.13.1.3.1	Definition of Existing Import Capacity Resource.
III.13.1.3.2	Qualified Capacity for Existing Import Capacity Resources.
III.13.1.3.3	Qualification Process for Existing Import Capacity Resources.
III.13.1.3.4	Definition of New Import Capacity Resource.
III.13.1.3.5	Qualification Process for New Import Capacity Resources.
III.13.1.3.5.1	Documentation of Import.
III.13.1.3.5.2	Import Backed by Existing External Resources.
III.13.1.3.5.3	Imports Backed by an External Control Area.
III.13.1.3.5.3.1	Imports Crossing Intervening Control Areas.
III.13.1.3.5.4	Capacity Commitment Period Election.
III.13.1.3.5.5	Initial Interconnection Analysis.
III.13.1.3.5.6	Review by Internal Market Monitor of Offers from New Import Capacity Resources and Existing Import Capacity Resources.
III.13.1.3.5.7	Qualification Determination Notification for New Import Capacity Resources.
III.13.1.3.5.8	Rationing Election.
III.13.1.4	Demand Resources.
III.13.1.4.1	Demand Resources.
III.13.1.4.1.1	Existing Demand Resources.

III.13.1.4.1.2	New Demand Resources.
III.13.1.4.1.2.1	Qualified Capacity of New Demand Resources.
III.13.1.4.1.2.2	Initial Analysis of Certain New Demand Resources.
III.13.1.4.1.3	Special Provisions for Real-Time Emergency Generation Resources.
III.13.1.4.2	Show of Interest Form for New Demand Resources.
III.13.1.4.2.1	Qualification Package for Existing Demand Resources.
III.13.1.4.2.2	Qualification Package for New Demand Resources.
III.13.1.4.2.2.1	[Reserved.]
III.13.1.4.2.2.2	Source of Funding.
III.13.1.4.2.2.3	Measurement and Verification Plan.
III.13.1.4.2.2.4	Customer Acquisition Plan.
III.13.1.4.2.2.4.1	Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.
III.13.1.4.2.2.4.2	Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.
III.13.1.4.2.2.4.3	Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.
III.13.1.4.2.2.5	Capacity Commitment Period Election.
III.13.1.4.2.2.6	Rationing Election.
III.13.1.4.2.3	Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.
III.13.1.4.2.4	Offers from New Demand Resources.
III.13.1.4.2.5	Notification of Qualification for Demand Resources.
III.13.1.4.2.5.1	Evaluation of Demand Resource Qualification Materials.
III.13.1.4.2.5.2	Notification of Qualification for Existing Demand Resources.
III.13.1.4.2.5.3	Notification of Qualification for New Demand Resources.
III.13.1.4.2.5.3.1	Notification of Acceptance to Qualify of a New Demand Resource.

III.13.1.4.2.5.3.2	Notification of Failure to Qualify of a New Demand Resource.
III.13.1.4.3	Measurement and Verification Applicable to All Demand Resources.
III.13.1.4.3.1	Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.
III.13.1.4.3.1.1	Optional Measurement and Verification Reference Reports.
III.13.1.4.3.1.2	Updated Measurement and Verification Documents.
III.13.1.4.3.1.3	Annual Certification of Accuracy of Measurement and Verification Documents.
III.13.1.4.3.1.4.	Record Requirement of Retail Customers Served.
III.13.1.4.3.2	Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.
III.13.1.4.3.2.1.	No Performance Data to Determine Demand Reduction Values.
III.13.1.4.3.3.	ISO Review of Measurement and Verification Documents.
III.13.1.4.3.4.	Measurement and Verification Costs.
III.13.1.4.4	Dispatch of Active Demand Resources During Event Hours.
III.13.1.4.4.1	Notification of Demand Resource Forecast Peak Hours.
III.13.1.4.4.2	Dispatch of Demand Resources during Real-Time Demand Resource Dispatch Hours.
III.13.1.4.4.3	Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.
III.13.1.4.5	Selection of Active Demand Resources For Dispatch.
III.13.1.4.5.1	Management of Real-Time Demand Response Assets and Real-Time Demand Response Resources.
III.13.1.4.5.2	Management of Real-Time Emergency Generation Assets and Real-Time Emergency Generation Resources.
III.13.1.4.5.3	[Reserved.]
III.13.1.4.6	Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at Dispatch Zones.
III.13.1.4.6.1	Establishment of Dispatch Zones.
III.13.1.4.6.2	Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

III.13.1.4.6.2.1	Real-Time Demand Response Resource Disaggregation.
III.13.1.4.6.2.2	Real-Time Emergency Generation Resource Disaggregation.
III.13.1.4.7	[Reserved.]
III.13.1.4.8	[Reserved.]
III.13.1.4.9	Restrictions on Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Registration.
III.13.1.4.9.1	Requirement for Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Retirement.
III.13.1.4.10	Providing Information On Real-Time Demand Response and Real-Time Emergency Generation Resource.
III.13.1.4.11.	Assignment of Demand Assets to a Demand Resource.
III.13.1.5	Offers Composed of Separate Resources.
III.13.1.5.A.	Notification of FCA Qualified Capacity.
III.13.1.6	Self-Supplied FCA Resources.
III.13.1.6.1	Self-Supplied FCA Resource Eligibility.
III.13.1.6.2	Locational Requirement for Self-Supplied FCA Resources.
III.13.1.7	Internal Market Monitor Review of Offers and Bids.
III.13.1.8	Publication of Offer and Bid Information.
III.13.1.9	Financial Assurance.
III.13.1.9.1	Financial Assurance for New Generating Capacity Resources and New Demand Resources Participating in the Forward Capacity Auction.
III.13.1.9.2	Financial Assurance for New Generating Capacity Resources and New Demand Resources Clearing in a Forward Capacity Auction.
III.13.1.9.2.1	Failure to Provide Financial Assurance or to Meet Milestone.
III.13.1.9.2.2	Release of Financial Assurance.
III.13.1.9.2.2.1	[Reserved.]
III.13.1.9.2.3	Forfeit of Financial Assurance.
III.13.1.9.2.4	Financial Assurance for New Import Capacity Resources.

III.13.1.9.3	Qualification Process Cost Reimbursement Deposit.
III.13.1.9.3.1	Partial Waiver of Deposit.
III.13.1.9.3.2	Settlement of Costs.
III.13.1.9.3.2.1	Settlement of Costs Associated With Resources Participating In A Forward Capacity Auction Of Reconfiguration Auction.
III.13.1.9.3.2.2	Settlement of Costs Associated With Withdrew From A Forward Capacity Auction Of Reconfiguration Auction.
III.13.1.9.3.2.3	Crediting Of Reimbursements.
III.13.1.10	Forward Capacity Auction Qualification Schedule.
III.13.2	Annual Forward Capacity Auction.
III.13.2.1	Timing of Annual Forward Capacity Auctions.
III.13.2.2	Amount of Capacity <u>Cleared Purchased</u> in Each Forward Capacity Auction.
III.13.2.3	Conduct of the Forward Capacity Auction.
III.13.2.3.1	Step 1: Announcement of Start-of-Round Price and End-of-Round Price.
III.13.2.3.2	Step 2: Compilation of Offers and Bids.
III.13.2.3.3	Step 3: Determination of the Outcome of Each Round.
III.13.2.3.4	Determination of Final Capacity Zones.
III.13.2.4	Forward Capacity Auction Starting Price <u>and the Cost of New Entry</u> .
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.
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.
III.13.2.5.2.2	Static De-List Bids and Export Bids.
III.13.2.5.2.3	Dynamic De-List Bids.
III.13.2.5.2.4	Administrative Export De-List Bids.

III.13.2.5.2.5	Bids Rejected for Reliability Reasons.
III.13.2.5.2.5.1	Compensation for Bids Rejected for Reliability Reasons.
III.13.2.5.2.5.2	Incremental Cost of Reliability Service From Non-Price Retirement Request Resources.
III.13.2.5.2.5.3	Retirement of Resources.
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.
III.13.2.6	Capacity Rationing Rule.
III.13.2.7	Determination of Capacity Clearing Prices.
III.13.2.7.1	Import-Constrained Capacity Zone Capacity Clearing Price Floor.
III.13.2.7.2	Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.
III.13.2.7.3	Capacity Clearing Price Floor.
III.13.2.7.3A	Treatment of Imports.
III.13.2.7.4	Effect of Capacity Rationing Rule on Capacity Clearing Price.
III.13.2.7.5	Effect of Decremental Repowerings on the Capacity Clearing Price.
III.13.2.7.6	Minimum Capacity Award.
III.13.2.7.7	Tie-Breaking Rules.
III.13.2.7.8	[Reserved.]
III.13.2.7.9	Capacity Carry Forward Rule.
III.13.2.7.9.1.	Trigger.
III.13.2.7.9.2	Pricing.
III.13.2.8	Inadequate Supply and Insufficient Competition.
III.13.2.8.1	Inadequate Supply.
III.13.2.8.1.1	Inadequate Supply in an Import-Constrained Capacity Zone.
III.13.2.8.1.2	System-Wide Inadequate Supply [Reserved.].
III.13.2.8.2	Insufficient Competition.
III.13.2.9	[Reserved.]

- III.13.3 Critical Path Schedule Monitoring.
 - III.13.3.1 Resources Subject to Critical Path Schedule Monitoring.
 - III.13.3.1.1 New Resources Clearing in the Forward Capacity Auction.
 - III.13.3.1.2 New Resources Not Offering or Not Clearing in the Forward Capacity Auction.
 - III.13.3.2 Quarterly Critical Path Schedule Reports.
 - III.13.3.2.1 Updated Critical Path Schedule.
 - III.13.3.2.2 Documentation of Milestones Achieved.
 - III.13.3.2.3 Additional Relevant Information.
 - III.13.3.2.4 Additional Information for Resources Previously Listed as Capacity.
 - III.13.3.3 Failure to Meet Critical Path Schedule.
 - III.13.3.4 Covering Capacity Supply Obligation where Resource will Not Achieve Commercial Operation by the Start of the Capacity Commitment Period.
 - III.13.3.5 Termination of Interconnection Agreement.
 - III.13.3.6 Withdrawal from Critical Path Schedule Monitoring.
- III.13.4 Reconfiguration Auctions.
 - III.13.4.1 Capacity Zones Included in Reconfiguration Auctions.
 - III.13.4.2 Participation in Reconfiguration Auctions.
 - III.13.4.2.1 Supply Offers.
 - III.13.4.2.1.1 Amount of Capacity That May Be Submitted in a Supply Offer in an 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.
 - III.13.4.2.1.2.1.1.2 Winter ARA Qualified Capacity.

III.13.4.2.1.2.1.2	Intermittent Power Resources.
III.13.4.2.1.2.1.2.1	Summer ARA Qualified Capacity.
III.13.4.2.1.2.1.2.2	Winter ARA Qualified Capacity.
III.13.4.2.1.2.1.3	Import Capacity Resources.
III.13.4.2.1.2.1.4	Demand Resources.
III.13.4.2.1.2.1.4.1	Summer ARA Qualified Capacity.
III.13.4.2.1.2.1.4.2	Winter ARA Qualified Capacity.
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.
III.13.4.2.1.2.2.1.2	Winter ARA Qualified Capacity.
III.13.4.2.1.2.2.2	Intermittent Power Resources.
III.13.4.2.1.2.2.2.1	Summer ARA Qualified Capacity.
III.13.4.2.1.2.2.2.2	Winter ARA Qualified Capacity.
III.13.4.2.1.2.2.2.3	Adjustment for Certain Intermittent Power Resources and Intermittent Settlement Only Resources.
III.13.4.2.1.2.2.3	Import Capacity Resources.
III.13.4.2.1.2.2.4	Demand Resources.
III.13.4.2.1.2.2.4.1	Summer ARA Qualified Capacity.
III.13.4.2.1.2.2.4.2	Winter ARA Qualified Capacity.
III.13.4.2.1.3	Adjustment for Significant Decreases in Capacity.
III.13.4.2.1.4	Amount of Capacity That May Be Submitted in a Supply Offer in a Monthly Reconfiguration Auction.
III.13.4.2.1.5	ISO Review of Supply Offers.
III.13.4.2.2	Demand Bids in Reconfiguration Auctions.
III.13.4.3	ISO Participation in Reconfiguration Auctions.
III.13.4.4	Clearing Offers and Bids in Reconfiguration Auctions.
III.13.4.5	Annual Reconfiguration Auctions.

III.13.4.5.1	Timing of Annual Reconfiguration Auctions.
III.13.4.5.2	Acceleration of Annual Reconfiguration Auction.
III.13.4.6	[Reserved.]
III.13.4.7	Monthly Reconfiguration Auctions.
III.13.4.8	Adjustment to Capacity Supply Obligations.
III.13.5	Bilateral Contracts in the Forward Capacity Market.
III.13.5.1	Capacity Supply Obligation Bilaterals.
III.13.5.1.1	Process for Approval of Capacity Supply Obligation Bilaterals.
III.13.5.1.1.1	Timing.
III.13.5.1.1.2	Application.
III.13.5.1.1.3	ISO Review.
III.13.5.1.1.4	Approval.
III.13.5.2	Capacity Load Obligations Bilaterals.
III.13.5.2.1	Process for Approval of Capacity Load Obligation Bilaterals.
III.13.5.2.1.1	Timing.
III.13.5.2.1.2	Application.
III.13.5.2.1.3	ISO Review.
III.13.5.2.1.4	Approval.
III.13.5.3	Supplemental Availability Bilaterals.
III.13.5.3.1	Designation of Supplemental Capacity Resources.
III.13.5.3.1.1	Eligibility.
III.13.5.3.1.2	Designation.
III.13.5.3.1.3	ISO Review.
III.13.5.3.1.4	Effect of Designation.
III.13.5.3.2	Submission of Supplemental Availability Bilaterals.
III.13.5.3.2.1	Timing.
III.13.5.3.2.2	Application.
III.13.5.3.2.3	ISO Review.
III.13.5.3.2.4	Effect of Supplemental Availability Bilateral.

III.13.6	Rights and Obligations.
III.13.6.1	Resources with Capacity Supply Obligations.
III.13.6.1.1	Generating Capacity Resources.
III.13.6.1.1.1	Energy Market Offer Requirements.
III.13.6.1.1.2	Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.
III.13.6.1.1.3	[Reserved.]
III.13.6.1.1.4	[Reserved.]
III.13.6.1.1.5	Additional Requirements for Generating Capacity Resources.
III.13.6.1.2	Import Capacity Resources.
III.13.6.1.2.1	Energy Market Offer Requirements.
III.13.6.1.2.2	Additional Requirements for Import Capacity Resources.
III.13.6.1.3	Intermittent Power Resources.
III.13.6.1.3.1	Energy Market Offer Requirements.
III.13.6.1.3.2	[Reserved.]
III.13.6.1.3.3	Additional Requirements for Intermittent Power Resources.
III.13.6.1.4	Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.
III.13.6.1.4.1	Energy Market Offer Requirements.
III.13.6.1.4.2	Additional Requirements for Settlement Only Resources.
III.13.6.1.5	Demand Resources.
III.13.6.1.5.1	Energy Market Offer Requirements.
III.13.6.1.5.2	Requirement that Offers Reflect Accurate Demand Response Capacity Resource Operating Characteristics.
III.13.6.1.5.3	Additional Requirements for Demand Resources.
III.13.6.1.5.4.	Demand Response Auditing.
III.13.6.1.5.4.1.	General Auditing Requirements for Demand Resources Excluding Demand Response Capacity Resources.
III.13.6.1.5.4.2.	General Auditing Requirements for Demand Response Capacity Resources.

III.13.6.1.5.4.3.	Seasonal DR Audits.
III.13.6.1.5.4.3.1.	Seasonal DR Audit Requirement.
III.13.6.1.5.4.3.2.	Failure to Request or Perform an Audit.
III.13.6.1.5.4.3.3.	Use of Event Performance Data to Satisfy Audit Requirements for Certain Resources.
III.13.6.1.5.4.3.3.1.	Demand Response Capacity Resources.
III.13.6.1.5.4.4.	Demand Resource Commercial Operation Audit.
III.13.6.1.5.4.5.	Additional Audits.
III.13.6.1.5.4.6.	Audit Methodologies.
III.13.6.1.5.4.7.	Requesting and Performing an Audit.
III.13.6.1.5.4.8.	New Demand Response Asset Audits.
III.13.6.1.5.4.8.1.	General Auditing Requirements for New Demand Response Assets.
III.13.6.1.5.5.	Reporting of Forecast Hourly Demand Reduction.
III.13.6.1.5.6.	Reporting of Monthly Maximum Forecast Hourly Demand Reduction.
III.13.6.2	Resources Without a Capacity Supply Obligation.
III.13.6.2.1	Generating Capacity Resources.
III.13.6.2.1.1	Energy Market Offer Requirements.
III.13.6.2.1.1.1	Day-Ahead Energy Market Participation.
III.13.6.2.1.1.2	Real-Time Energy Market Participation.
III.13.6.2.1.2	Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.
III.13.6.2.2	[Reserved.]
III.13.6.2.3	Intermittent Power Resources.
III.13.6.2.3.1	Energy Market Offer Requirements.

III.13.6.2.3.2	Additional Requirements for Intermittent Power Resources.
III.13.6.2.4	Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.
III.13.6.2.4.1	Energy Market Offer Requirements.
III.13.6.2.4.2	Additional Requirements for Settlement Only Resources.
III.13.6.2.5	Demand Resources.
III.13.6.2.5.1.	Energy Market Offer Requirements.
III.13.6.2.5.1.1.	Day-Ahead Energy Market Participation.
III.13.6.2.5.1.2.	Real-Time Energy Market Participation.
III.13.6.2.5.2.	Additional Requirements for Demand Response Capacity Resources Having No Capacity Supply Obligation.
III.13.6.3	Exporting Resources.
III.13.6.4	ISO Requests for Energy.
III.13.6.4.1	Real-Time High Operating Limit.
III.13.7	Performance, Payments and Charges in the FCM.
III.13.7.1	Performance Measures.
III.13.7.1.1	Generating Capacity Resources.
III.13.7.1.1.1	Definition of Shortage Events.
III.13.7.1.1.1.A	Shortage Event Availability Score.
III.13.7.1.1.2	Hourly Availability Scores.
III.13.7.1.1.3	Hourly Availability MW.
III.13.7.1.1.4	Availability Adjustments.
III.13.7.1.1.5	Poorly Performing Resources.
III.13.7.1.2	Import Capacity.
III.13.7.1.2.1	Availability Adjustments.
III.13.7.1.3	Intermittent Power Resources.
III.13.7.1.4	Settlement Only Resources.
III.13.7.1.4.1	Non-Intermittent Settlement Only Resources.
III.13.7.1.4.2	Intermittent Settlement Only Resources.

III.13.7.1.5	Demand Resources.
III.13.7.1.5.1	Capacity Values of Demand Resources.
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.
III.13.7.1.5.2	Capacity Values of Certain Distributed Generation.
III.13.7.1.5.3	Demand Reduction Values.
III.13.7.1.5.4	Calculation of Demand Reduction Values for On- Peak Demand Resources.
III.13.7.1.5.4.1	Summer Seasonal Demand Reduction Value.
III.13.7.1.5.4.2	Winter Seasonal Demand Reduction Value.
III.13.7.1.5.5	Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.
III.13.7.1.5.5.1	Summer Seasonal Demand Reduction Value.
III.13.7.1.5.5.2	Winter Seasonal Demand Reduction Value.
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.
III.13.7.1.5.7.1	Summer Seasonal Demand Reduction Value.
III.13.7.1.5.7.2	Winter Seasonal Demand Reduction Value.
III.13.7.1.5.7.3	Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources.
III.13.7.1.5.7.3.1	Determination of the Hourly Real-Time Demand Response Resource Deviation.
III.13.7.1.5.8	Demand Reduction Values for Real-Time Emergency Generation Resources.
III.13.7.1.5.8.1	Summer Seasonal Demand Reduction Value.

III.13.7.1.5.8.2	Winter Seasonal Demand Reduction Value.
III.13.7.1.5.8.3	Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Emergency Generation Resources.
III.13.7.1.5.8.3.1	Determination of the Hourly Real- Time Emergency Generation Resource Deviation.
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.
III.13.7.1.5.10.	Demand Response Capacity Resources.
III.13.7.1.5.10.1.	Hourly Available MW.
III.13.7.1.5.10.1.1.	Adjusted Audited Demand Reduction.
III.13.7.1.5.10.1.2.	Hourly Adjusted Audited Demand Reduction.
III.13.7.1.5.10.2.	Availability Adjustments.
III.13.7.1.6	Self-Supplied FCA Resources.
III.13.7.2	Payments and Charges to Resources.
III.13.7.2.1	Generating Capacity Resources.
III.13.7.2.1.1	Monthly Capacity Payments.
III.13.7.2.2	Import Capacity.
III.13.7.2.2.A	Export Capacity.
III.13.7.2.3	Intermittent Power Resources.
III.13.7.2.4	Settlement Only Resources.
III.13.7.2.4.1	Non-Intermittent Settlement Only Resources.
III.13.7.2.4.2	Intermittent Settlement Only Resources.
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.
III.13.7.2.5.2	Monthly Capacity Payments for Real-Time Emergency Generation Resources.

III.13.7.2.5.3.	Energy Settlement for Real-Time Demand Response Resources.
III.13.7.2.5.4.	Energy Settlement for Real-Time Emergency Generation Resources.
III.13.7.2.5.4.1.	Adjustment for Net Supply Generator Assets.
III.13.7.2.6	Self-Supplied FCA Resources.
III.13.7.2.7	Adjustments to Monthly Capacity Payments.
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.
III.13.7.2.7.1.1.1	Hourly PER Calculations.
III.13.7.2.7.1.1.2	Monthly PER Application.
III.13.7.2.7.1.2	Availability Penalties.
III.13.7.2.7.1.3	Availability Penalty Caps.
III.13.7.2.7.1.4	Availability Credits for Capacity Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources.
III.13.7.2.7.2	Import Capacity.
III.13.7.2.7.2.1	External Transaction Offer and Delivery Performance Adjustments.
III.13.7.2.7.2.2	Exceptions.
III.13.7.2.7.3	Intermittent Power Resources.
III.13.7.2.7.4	Settlement Only Resources.
III.13.7.2.7.4.1	Non-Intermittent Settlement Only Resources.
III.13.7.2.7.4.2	Intermittent Settlement Only Resources.
III.13.7.2.7.5	Demand Resources.
III.13.7.2.7.5.1	Calculation of Monthly Capacity Variances.
III.13.7.2.7.5.2	Negative Monthly Capacity Variances.
III.13.7.2.7.5.3	Positive Monthly Capacity Variances.
III.13.7.2.7.5.4	Determination of Net Demand Resource Performance Penalties and Demand Resource Performance Incentives .

III.13.7.2.7.6	Self-Supplied FCA Resources.
III.13.7.3	Charges to Market Participants with Capacity Load Obligations.
III.13.7.3.1	Calculations of Capacity Requirement and Capacity Load Obligation.
III.13.7.3.1.1	HQICC Used in the Calculation of Capacity Requirements.
III.13.7.3.1.2	Charges Associated with Self-Supplied FCA Resources.
III.13.7.3.1.3	Charges Associated with Dispatchable Asset Related Demands.
III.13.7.3.2	Excess Revenues.
III.13.7.3.3	Capacity Transfer Rights.
III.13.7.3.3.1	Definition and Payments to Holders of Capacity Transfer Rights.
III.13.7.3.3.2	Allocation of Capacity Transfer Rights.
III.13.7.3.3.3	Allocations of CTRs Resulting From Revised Capacity Zones.
III.13.7.3.3.4	Specifically Allocation of CTRs Associated with Transmission Upgrades.
III.13.7.3.3.5	[Reserved.]
III.13.7.3.3.6	Specifically Allocated CTRs for Pool Planned Units.
III.13.7.3.4	Forward Capacity Market Net Charge Amount.
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.
III.13.8.2	Filing of Forward Capacity Auction Results and Challenges Thereto.
III.13.8.3	[Reserved.]
III.13.8.4	[Reserved.]
III.14	[Reserved.]

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section III.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Resource, New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the financial assurance deposit described in Section III.13.1.9.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1. ~~A New Generating Capacity Resource may elect, during the qualification process, to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, as described in Section III.13.1.1.2.2.4.~~

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted

as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if: ~~(i) it never previously received any payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010, except any such payment that is received after the resource has cleared as a New Generating Capacity Resource in a Forward Capacity Auction; and (ii) it has not cleared in any previous Forward Capacity Auction.~~

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than \$200 per kilowatt of the whole resource's summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than \$100 per kilowatt of the whole resource's summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The \$100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.

The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output greater than 2 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, but less than or equal to the greater of: (i) 20 percent of the summer Qualified

Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than \$200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section does not cause the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement, the Project Sponsor must submit a New Capacity Qualification Package but is not required to submit a New Capacity Show of Interest Form for the incremental amount by the New Capacity Qualification Deadline. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.3 causes the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement or MW amount approved pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), the Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than \$200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form

pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.1.5. Treatment of Resources that are Partially New and Partially Existing.

For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.1.3 or Section III.13.1.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline. A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

III.13.1.1.1.7 Renewable Technology Resources.

To participate in the Forward Capacity Market as a Renewable Technology Resource, a Generating Capacity Resource must satisfy the following requirements:

- (a) receive an out-of-market revenue source supported by a state- or federally-regulated rate, charge or other regulated cost recovery mechanism;
- (b) qualify as a renewable or alternative energy generating resource under any New England state's mandated (either by statute or regulation) renewable or alternative energy portfolio standards as in effect on January 1, 2014, or, in states without a standard, qualify under that state's renewable energy goals as a renewable resource (either by statute or regulation) as in effect on January 1, 2014. The resource must qualify as a renewable or alternative energy generating resource in the state in which it is geographically located;
- (c) participate in a Forward Capacity Auction for a Capacity Commitment Period beginning on or after June 1, 2018 as a New Generating Capacity Resource pursuant to Section III.13.1.1, and;
- (d) has been designated for treatment as a Renewable Technology Resource pursuant to Section III.13.1.1.2.9.

An Export De-List Bid or Administrative Export De-List Bid may not be submitted for Generating Capacity Resources that assumed a Capacity Supply Obligation by participating in a Forward Capacity Auction as a Renewable Technology Resource.

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.

For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also submit to the ISO an Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of

the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the financial assurance deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. Upon submission of the financial assurance deposit by the Project Sponsor pursuant to Section III.13.1.9.1, the resource is obligated to participate and will be included in the Forward Capacity Auction at its FCA Qualified Capacity amount at the Forward Capacity Auction Starting Price. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, material changes (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein. The New Capacity Show of Interest Form is available on the ISO website. A New Capacity Show of Interest Form to which a material change has been made shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor's contact information; the Project Sponsor's ISO customer status; the project's expected Commercial Operation date; the project address or location, and if relevant, asset identification number; the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall have the same meaning as set forth in Schedule 22 or Schedule 23, as applicable, of Section II of the Transmission, Markets and Services Tariff. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market

rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must submit, with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall mean that: (i) the Project Sponsor is the owner in fee simple of the real property on which the project will be located; (ii) the Project Sponsor holds a valid written leasehold interest in the real property on which the project will be located; (iii) the Project Sponsor holds a valid written option, exercisable solely by the Project Sponsor or its assignee, to purchase or lease property on which the project will be located; or (iv) the Project Sponsor holds a duly executed written contract to purchase or lease the real property on which the project will be located. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits.** In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing.** In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders.** In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2.2(d) and that accounts for more than five percent of the total project cost.

(d) **Substantial Site Construction.** In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery.** In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing.** In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (d) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent Commercial Operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning.** In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation.** In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. Offer Information.

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity at or above the Economic Minimum Limit to which offers

may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity Resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 the OATT.

III.13.1.1.2.2.4. Capacity Commitment Period Election.

In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to ~~four~~six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity.

In addition to the information described elsewhere in this Section III.13.1.1.2.2.5:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource and Intermittent Settlement Only Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource or the Intermittent Settlement Only Resource.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided

in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a material change (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource's Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest

Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s), as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

(g) New Generating Capacity Resources, or portions thereof, shall not be considered to have met their Capacity Supply Obligation for the purposes of this Forward Capacity Market and shall not receive compensation if any upgrades to be completed by the Project Sponsor required to remove overlapping interconnection impacts as identified in (f) have not been completed, including, any upgrades identified in

a restudy pursuant to Section 3.2.1.3 of Schedule 22 and Section 1.7.1.3 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff and, if necessary, requests for the interconnection of an Elective Transmission Upgrade, in time for the Capacity Commitment Period unless the Capacity Supply Obligation is appropriately covered.

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource's New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

- (a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;
- (b) whether the critical path schedule includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule are reasonable and likely to be met;
- (d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and
- (e) whether, in the case of an Intermittent Power Resource or Intermittent Settlement Only Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a resource shall be the lesser of the resource's

summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. [Reserved.]

III.13.1.1.2.7. Opportunity to Consult with Project Sponsor.

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or

to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

- (a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;
- (b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource's New Capacity Qualification Package was not accepted;
- (c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);
- (d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource's summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;
- (e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to

their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Generating Capacity Resource; (ii) for the notification to a Conditional Qualified New Generating Capacity Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Generating Capacity Resource, the Queue Position of the Conditional Qualified New Generating Capacity Resource; and

(f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal Market Monitor's determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.1.2.9 Renewable Technology Resource Election.

A Project Sponsor or Market Participant electing Renewable Technology Resource treatment for the FCA Qualified Capacity of a New Generating Capacity Resource shall submit a Renewable Technology Resource election form no later than five Business Days after the date on which the ISO provides qualification determination notifications pursuant to Section III.13.1.1.2.8. Only the portion of the FCA Qualified Capacity of the resource that meets the requirements of Section III.13.1.1.1.7 is eligible for treatment as a Renewable Technology Resource.

Renewable Technology Resource elections may not be modified or withdrawn after the deadline for submission of the Renewable Technology Resource election form.

III.13.1.1.2.10 Determination of Renewable Technology Resource Qualified Capacity.

(a) If the total FCA Qualified Capacity of Renewable Technology Resources exceeds the cap specified in subsections (b), (c) and (d) the qualified capacity value of each resource shall be prorated by the ratio of the cap divided by the total FCA Qualified Capacity. The ISO shall notify the Project Sponsor or Market Participant, as applicable, of the Qualified Capacity value of its resource no more than three Business Days after the deadline for submitting Renewable Technology Resource elections.

(b) The cap for the Capacity Commitment Period beginning on June 1, 2018 is 200 MW.

(c) The cap for the Capacity Commitment Period beginning on June 1, 2019 is 400 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior Capacity Commitment Period.

(d) The cap for each Capacity Commitment Period beginning on or after June 1, 2020 is 600 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior two Capacity Commitment Periods.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Resource or Existing Demand Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth

Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006 summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be established pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e).

(b) The Intermittent Power Resource's or Intermittent Settlement Only Resource's summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial

Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.

- (a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in each of the previous winter periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.
- (b) The Intermittent Power Resource's and Intermittent Settlement Only Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.2(a).
- (c) The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.
- (d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

- (a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification

process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the ~~three~~two

treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to ~~Section III.13.1.2.2.4(b) or~~ Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

~~(b) A Lead Market Participant may elect: (i) to submit a Static De-List Bid or a Permanent De-List Bid for the difference between the summer Qualified Capacity calculated pursuant to Section III.13.1.2.2.1.1 and the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.13.1.2.2.1.1 for the Forward Capacity Auction. [Reserved.]~~

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New

Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only Resource) has a summer Qualified Capacity that exceeds, ~~by the threshold specified below,~~ its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity. ~~submit a Static De List Bid or a Permanent De List Bid in an Existing Capacity Qualification Package for at least the difference between the summer Qualified Capacity and the winter Qualified Capacity, at the Forward Capacity Auction Starting Price. If the Lead Market Participant makes no election, the ISO shall submit a Static De List Bid 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) for the difference between the resource's summer Qualified Capacity and the winter Qualified Capacity at the Forward Capacity Auction Starting Price. The Internal Market Monitor shall review each bid made pursuant to this Section III.13.1.2.2.5.2, and if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Bids made pursuant to this Section III.13.1.2.2.5.2 shall be subject to a reliability review as described in Section III.13.2.5.2.5, as required. This Section III.13.1.2.2.5.2 shall not apply if the summer Qualified Capacity of a resource is greater than the winter Qualified Capacity of that resource by less than the lesser of: (i) 2 MW, or (ii) two percent of the summer Qualified Capacity of that resource.~~

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, and if accepted by the ISO shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an

Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid. ~~All Static De-List Bids and Permanent De-List Bids submitted under Section III.13.1.2.2.4(b) associated with a significant decrease in capacity must be identified in the Existing Capacity Qualification Package.~~

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

The Dynamic De-List Bid Threshold beginning with the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018) shall be \$3.94/kW-month. The Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Dynamic De-List Bid Threshold shall be filed with the Commission under Section 205 of the Federal Power Act prior to the Existing Capacity Qualification Deadline for the associated Forward Capacity Auction.

III.13.1.2.3.1.1. Static De-List Bids.

An Existing Generating Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation at prices at or above the Dynamic De-List Bid Threshold during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section

III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests). Static De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.2. Permanent De-List Bids.

An Existing Generating Capacity Resource seeking to specify a price below which it would not accept a Capacity Supply Obligation permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource's full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource ~~or~~, an Intermittent Settlement Only Resource or a Renewable Technology Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource

submits de-list and export bids totaling the resource's full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource ~~or~~ an Intermittent Settlement Only Resource or a Renewable Technology Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity

Commitment Period. Administrative Export De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.

A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.

The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a resource that has a Permanent De-List Bid rejected by the Internal Market Monitor, a Non-Price Retirement Request may be submitted within 14 days after the resource receives notice of the rejection or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.

III.13.1.2.3.1.5.3. Reliability Review of Non-Price Retirement Requests.

The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

III.13.1.2.3.1.5.4. Obligation to Retire.

A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5.3(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the

obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.

III.13.1.2.3.1.6. Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. Internal Market Monitor Review.

The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

- (i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.
- (ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.
- (iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive de-listing of each individual asset in preferred de-list order.
- (iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of bids as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The bids of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will reject the bid as described in Section III.13.1.2.3.2.1.1.

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III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

For purposes of this Section III.13.1.2.3.2, a Static De-List Bid, Permanent De-List Bid, or Export Bid shall be associated with a pivotal supplier if, using the best available estimates of FCA Qualified Capacity available at that time: (1) at the Forward Capacity Auction Starting Price, the total amount of ~~summer Qualified Capacity~~ FCA Qualified Capacity of all Existing Capacity Resources in the New England Control Area minus the Installed Capacity Requirement (net of HQICCs) is less than or equal to the greater of:

(a) the amount of ~~capacity~~ FCA Qualified Capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and

(b) the amount of ~~capacity~~ FCA Qualified Capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW;

or (2) where the bid is associated with a resource in an import-constrained Capacity Zone, if at the Forward Capacity Auction Starting Price, the total amount of ~~summer Qualified Capacity~~ FCA Qualified Capacity of all Existing Capacity Resources in the import-constrained Capacity Zone minus the Local Sourcing Requirement for the import-constrained Capacity Zone is less than or equal to the greater of:

(a) the amount of ~~capacity~~ FCA Qualified Capacity from all Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and

(b) the amount of ~~capacity~~ FCA Qualified Capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 100 MW.

In making this determination, the total amount of ~~summer Qualified Capacity~~ FCA Qualified Capacity of all Existing Capacity Resources will be reduced by an amount equal to the total of all pending Non-Price Retirement Requests and Permanent De-List Bids other than those submitted by the Lead Market Participant for the resource being evaluated, and the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource will include any capacity subject to a pending Non-Price Retirement Request or Permanent De-List Bid. The determination whether a Lead Market Participant is pivotal will be included in the qualification determination notification described in Section III.13.1.2.4. If the applicable Installed Capacity Requirement (net of HQICCs) and Local Sourcing Requirement are not finalized at the time that the Internal Market Monitor must make this determination, then the Internal Market Monitor shall use the best available estimates of those values available at that time, and shall publish those estimated values to the ISO website no later than the date that the qualification determination notifications are issued.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids Above the Dynamic De-List Bid Threshold, and Permanent De-List Bids Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid, each Export Bid above the Dynamic De-List Bid Threshold, and each Permanent De-List Bid above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the Existing Generating Capacity Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); (3) reasonable risk premium assumptions (as determined pursuant to Section III.13.1.2.3.2.1.4); and (4) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). Sufficient documentation and information about each of these bid components must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments and risk premiums, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate. The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

III.13.1.2.3.2.1.1.1. Review of Permanent De-List Bids and Export Bids.

(a) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the

determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(b) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(c) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.2.3, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1(c), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected 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 Lead Market Participant for such a resource may elect to have the ISO-determined bid entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b) by so indicating in a filing with the Commission in response to the informational filing described in Section III.13.8.1(a). Such a filing, and notification to the ISO of any such election, shall be made in accordance with the terms of Section III.13.8.1(b) and shall not limit the other rights provided under that section. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. In no case shall rejection of a de-list bid by the Internal Market Monitor

restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.

- (a) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.
- (b) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid

pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

- (c) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.2(b), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected 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. In such a case, no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to submit revised prices for the Static De-List Bid for the resource at prices equal to or less than 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 and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. If no such election is made, and the Existing Generating Capacity Resource is entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c), then nothing in this subsection shall restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

III.13.1.2.3.2.1.2. Net Going Forward Costs.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net going forward costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. A Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing Generating Capacity Resource's net going forward costs based on a review of the data submitted in the following formula. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{[GFC - (IMR - PER)] \times InfIndex}{(CQ_{Summer, kw}) \times (12, months)}$$

Where:

GFC = annual going forward costs, in dollars. These are costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data

used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

$CQ_{\text{summer}}kW$ = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid), this value shall be calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be \$0.00. As soon as practicable, the resource's total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected

InfIndex = inflation index. $\text{infIndex} = (1 + i)^4$

Where: “*i*” is the most recent reported 4-Year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource’s performance during reserve deficiencies.

III.13.1.2.3.2.1.4. Risk Premium.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. This documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.13.1.2.3.2.1.2 may be included in this risk premium component. In support of the resource’s risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource’s participation in the Forward Capacity Market is consistent with the participant’s corporate risk management practices.

III.13.1.2.3.2.1.5. Opportunity Costs.

To the extent that an Existing Generating Capacity Resource submitting a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, expected Capacity Performance Payments, or risk premium components of the bid, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section

III.13.1.2.2.4, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. Administrative Export De-List Bids.

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

Age of Existing	Remaining Life	Annual Rate of Capital Cost
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Resource (years)	(years)	Recovery
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource’s annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource’s annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{\text{Cost Of Capital}}{(1 - (1 + \text{CostOfCapital})^{-\text{RemainingLife}})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Qualification Determination Notification for Existing Capacity.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid including a determination whether the Lead Market Participant is pivotal as described in Section III.13.1.2.3.2 and indicating whether the bid has been accepted for participation in the Forward Capacity Auction. Where a Static De-List Bid, Permanent De-List Bid, Export Bid, or Administrative Export De-List Bid is not accepted for participation in the Forward Capacity Auction as a result of the Internal Market Monitor’s review pursuant to Section III.13.1.2.3.2,

the notification shall include an explanation of the reasons the Existing Capacity Qualification Package was not accepted and shall include the resource's net going forward costs and opportunity costs as determined by the Internal Market Monitor. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external Demand Resource may not be an Existing Import Capacity Resource or a

New Import Capacity Resource. External nodes shall be mapped to Capacity Zones as shown in the following table:

External Node Common Name	Capacity Zone
NB-NE External Node	Maine
HQ Phase I/II External Node	Rest-of-Pool
Highgate External Node	Rest-of-Pool
NY-NE AC External Node	Rest-of-Pool
Cross Sound Cable External Node	CT

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. Qualified Capacity for Existing Import Capacity Resources.

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3. Qualification Process for Existing Import Capacity Resources.

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

(a) No later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting each Existing Import Capacity Resource must also submit to the ISO: (i) documentation of a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, including documentation of the MW value of the contract; or (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Existing Import Capacity Resource during the Capacity Commitment Period, together with information to establish the summer and winter ratings of the resource(s) backing the import. In either case, the Market Participant must specify the interface over which the capacity will be imported.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply. An Existing Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, Existing Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

(c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3 for the duration of the contracts as listed. For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3, no later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3.

Contract Description	MW	Contract End Date
NYPA: NY – NE: CMEEC	13.2	8/31/2025
NYPA: NY – NE: MMWEC	53.3	8/31/2025
NYPA: NY – NE: Pascoag	2.3	8/31/2025
NYPA: NY– NE: VELCO	15.3	8/31/2025
	84.1	

VJO: Highgate — NE	Up to 225	10/31/2016
VJO: Highgate — NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II — NE	Up to 110	10/31/2016

III.13.1.3.4. Definition of New Import Capacity Resource.

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

For each New Import Capacity Resource, the Market Participant submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the entire Capacity Commitment Period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract; (iii)

proof of ownership or direct control over one or more External Resources that will be used to back the New Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iv) documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load. For each New Import Capacity Resource, the Market Participant must specify the interface over which the capacity will be imported. The Market Participant must indicate whether the import is associated with any investment in transmission that increases New England's import capability. If the import will be backed by a single new External Resource, the Market Participant submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the Market Participant, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the New Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.

The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) For imports crossing a single intervening Control Area, the Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing. (2) For imports crossing more than one intervening Control Area, in addition to the requirements above, the Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load. (3) The Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.13.1.3.5.4. Capacity Commitment Period Election.

The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall not apply. A New Import Capacity Resource may not elect to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears.

III.13.1.3.5.5. Initial Interconnection Analysis.

The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources and Existing Import Capacity Resources.

In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from Existing Import Capacity Resources and New Import Capacity Resources. An offer from an Existing Import Capacity Resource or a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

III.13.1.3.5.8. Rationing Election.

The rationing election described in Section III.13.1.1.2.2.3(b) shall not apply. A New Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, New Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

III.13.1.4. Demand Resources.

III.13.1.4.1. Demand Resources.

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with an early Commercial Operation Date shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2017. No resource shall be permitted to participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life.

Demand Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Resource. Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market Participant for a resource shall include the Enrolling Participant for a Demand Resource.

III.13.1.4.1.1. Existing Demand Resources.

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to (i) Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction, or (ii) Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program, as defined in Appendix E of this Market Rule 1, before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.

III.13.1.4.1.2. New Demand Resources.

A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined

as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.

For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources

For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.3. Special Provisions for Real-Time Emergency Generation Resources.

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to

Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.4.2. Show of Interest Form for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date

by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor's New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. Qualification Package for Existing Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. Qualification Package for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1. [Reserved.]

III.13.1.4.2.2.2. Source of Funding.

The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3. Measurement and Verification Plan.

For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4. Customer Acquisition Plan.

A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1. Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.

For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.2.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete

III.13.1.4.2.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor's ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor's program to deliver capacity to meet the Demand Resource Project Sponsor's Forward Capacity Auction obligations, and must include each customer's projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor's ability to fulfill its obligation by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource Project Sponsor shall be subject to the ISO's critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. Capacity Commitment Period Election.

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to ~~four~~six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period

associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.2.5.

III.13.1.4.2.2.6. Rationing Election.

The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form. A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. Offers From New Demand Resources.

All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package

the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

III.13.1.4.2.5. Notification of Qualification for Demand Resources.

III.13.1.4.2.5.1. Evaluation of Demand Resource Qualification Materials.

The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

- (a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;
- (b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;
- (d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and
- (e) whether the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.

For each Existing Demand Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type; and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located,

and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. Notification of Qualification for New Demand Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.

For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource's summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.

For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.3. Measurement and Verification Applicable to All Demand Resources.

To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. A Net Supply Generator Asset or other Generator Asset located at the same Retail Delivery Point as a Demand Response Asset that is associated with a Demand Response Capacity Resource may not participate in the Forward Capacity Market as a Generating Capacity Resource, provided that this exclusion shall not apply to a Generator Asset if it is separately metered and its output is added to the metered load as measured at the Retail Delivery Point. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects in reducing demand coincident with Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours such that the reported monthly Demand Reduction Value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the

Demand Resource project's Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor's total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor's total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Demand Resource Project Sponsors. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications,

measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor's offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors shall maintain records of retail customers served including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly Demand Reduction Values. For Demand Resource projects targeting customer facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor shall maintain records as described above for customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, or shall maintain records of aggregated Demand Reduction Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently delisted from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.

The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation, Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, 2017, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 2017, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity Commitment Periods commencing on or after June 1, 2017, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2017, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated based upon the Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the Retail Delivery Point, the associated Real-

Time Emergency Generation Resource's Demand Reduction Value shall be calculated based upon the Average Hourly Load Reduction.

III.13.1.4.3.2.1. No Performance Data to Determine Demand Reduction Values.

Should a new Demand Resource, other than a Demand Response Capacity Resource, enter service at a time such that there is no performance data for June, July, August, December or January upon which to establish summer or winter seasonal Demand Reduction Values, and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, then the summer or winter seasonal Demand Reduction Values will be the simple average of its Demand Reduction Values for those months with a Capacity Supply Obligation. For a new Demand Resource, other than a Demand Response Capacity Resource, that enters service outside of the summer DR Auditing Period or winter DR Auditing Period and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, the Demand Resource Commercial Operation Audit results shall be used in the determination of the summer or winter seasonal Demand Reduction Value.

III.13.1.4.3.3. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.13.1.4.3.4. Measurement and Verification Costs.

Costs associated with measurement and verification of the Demand Resource project shall be borne by the Demand Resource Project Sponsor. Demand Resource Project Sponsors submitting application materials and Measurement and Verification Documents for review during the Forward Capacity Auction qualification process shall be subject to the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.4.4. Dispatch of Active Demand Resources During Event Hours.

III.13.1.4.4.1. Notification of Demand Resource Forecast Peak Hours.

The ISO shall issue notice to Market Participants concerning Demand Resource Forecast Peak Hours on the day before the relevant Operating Day. The notice issued pursuant to this section is for informational purposes only and shall not constitute a Dispatch Instruction.

III.13.1.4.4.2. Dispatch of Demand Resources During Real-Time Demand Resource Dispatch Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Demand Response Resources to curtail and restore loads during Real-Time Demand Resource Dispatch Hours. Dispatch Instructions shall apply to Real-Time Demand Response Resources. The amount of Demand Resources dispatched for each Real-Time Demand Resource Dispatch Hour will be the amount that the ISO determines is necessary to meet the reserve deficiency. The ISO may issue Dispatch Instructions that reduce or increase the amount dispatched in each hour.

III.13.1.4.4.3. Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Emergency Generation Resources to curtail and restore loads during Real-Time Emergency Generation Event Hours. Dispatch Instructions shall apply to specific Real-Time Emergency Generation Resources. The amount of Real-Time Emergency Generation Resources dispatched for each Real-Time Emergency Generation Event Hour will be the amount the ISO determines is necessary to meet the reserve deficiency.

III.13.1.4.5. Selection of Active Demand Resources For Dispatch.

III.13.1.4.5.1. Management of Real-Time Demand Response Assets and Real-Time Demand Response Resources.

A Market Participant must manage its Real-Time Demand Response Assets that are registered as a component of a Real-Time Demand Response Resource as of the first of a month so that the Real-Time Demand Response Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Demand Response Assets cause, or potentially cause, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to restore the loads of such assets that have

already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Demand Response Asset or to restore the load of a dispatched Real-Time Demand Response Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the restoration of that asset. Market Participants with Real-Time Demand Response Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Demand Response Resources consisting of an aggregation of more than one Real-Time Demand Response Asset shall report the load reduction and consumption, or generator output of the resource, to the ISO as the sum of the load reduction, consumption, or generator output of the individual assets making up that resource. Real-Time Demand Response Resources shall be assigned a unique resource identification number. The load reduction and consumption, or generator output of a Real-Time Demand Response Resource is reported to the ISO as a single set of values. A Real-Time Demand Response Resource shall consist of one or more Real-Time Demand Response Assets that are located within the same Dispatch Zone.

III.13.1.4.5.2. Management of Real-Time Emergency Generation Assets and Real-Time Emergency Generation Resources.

A Market Participant must manage its Real-Time Emergency Generation Assets that are registered as a component of a Real-Time Emergency Generation Resource as of the first of a month so that the Real-Time Emergency Generation Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Emergency Generation Assets causes, or potentially causes, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to discontinue the output of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Emergency Generation Asset or to discontinue the output of a dispatched Real-Time Emergency Generation Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the discontinued output of that asset. Market Participants with Real-Time Emergency Generation Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Emergency Generation Resources consisting of an aggregation of more than one Real-Time Emergency Generation Asset shall report the generator output of the resource to the ISO as the sum of the generator outputs of the individual assets making up that resource. Real-Time Emergency Generation Resources shall be assigned a unique resource identification number. The generator output of a Real-Time Emergency Generation Resource is reported to the ISO as a single set of values. A Real-Time Emergency Generation Resource shall consist of one or more Real-Time Emergency Generation Assets that are located within the same Dispatch Zone.

III.13.1.4.5.3. [Reserved.]

III.13.1.4.6. Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at Dispatch Zones.

III.13.1.4.6.1. Establishment of Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location and dispatch of Demand Response Capacity Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources. Dispatch Zones shall not change during a Capacity Commitment Period. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.13.1.4.6.2. Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

III.13.1.4.6.2.1. Real-Time Demand Response Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Demand Response Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Demand Response Resource into one or more Real-Time Demand Response Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply

Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.6.2.2. Real-Time Emergency Generation Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Emergency Generation Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Emergency Generation Resource into one or more Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.7. [Reserved.]

III.13.1.4.8. [Reserved.]

III.13.1.4.9. Restrictions on Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Registration.

A Market Participant may not register and, if previously registered, must retire in accordance with Section III.13.1.4.9.1, a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

III.13.1.4.9.1. Requirement for Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Retirement.

A Market Participant must retire a previously registered Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of customers specified in subsections (a) or (b) of Section III.13.1.4.9 no later than 12 months from the date that the ISO receives notice that the relevant electric retail regulatory authority prohibits such customer's demand response to be bid into the ISO-administered markets or programs or May 31, 2013, whichever is later.

III.13.1.4.10. Providing Information On Demand Response Capacity, Real-Time Demand Response and Real-Time Emergency Generation Resources.

If requested by a Market Participant with a registered Load Asset, the ISO will provide the following information about end-use customers served by the Market Participant: (a) whether the end-use customer's facility is registered with the ISO as part of an asset and whether the asset is associated with a Demand Response Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource, and; (b) the load reduction capability of the asset, as specified in the ISO's asset registration system, to which the end-use customer's facility is registered.

III.13.1.4.11. Assignment of Demand Assets to a Demand Resource.

The following mapping provisions apply to Demand Resources other than Demand Response Capacity Resources, the mapping for which is addressed in Appendix E to Market Rule 1.

(a) When a demand asset can be mapped to more than one Demand Resource, any demand assets shall be mapped to a commercial Demand Resource whose demand reduction capability is less than the

lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period, before being mapped to a non-commercial Demand Resource or non-commercial increment of a Demand Resource.

(b) A demand asset cannot be unmapped from a Demand Resource if, following the unmapping, the sum of the audit values of the remaining demand assets that are mapped to the Demand Resource would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.2.4.5.3. Offers composed of separate resources may not be modified or withdrawn after the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Resource, April through November where the summer resource is a Demand Resource) of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period (October through May where the summer resource is not a Demand Resource, December through March where the summer resource is a Demand Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing

Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource or Intermittent Settlement Only Resource. If the winter capacity of the offer composed of separate resources in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone.

(e) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained.

(f) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone.

(g) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource.

(h) A Renewable Technology Resource may only participate in an offer composed of separate resources if its FCA Qualified Capacity has not been prorated pursuant to Section III.13.1.1.2.10.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than 5 Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource's final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource's financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the financial assurance deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c) and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity's ~~share of Installed Capacity Requirement~~ Capacity Load Obligation in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not

exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

- (a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.
- (b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.
- (c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.
- (d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.
- (e) If a Permanent De-List Bid above \$1.00/kW-month or a Static De-List Bid is approved by the Internal Market Monitor, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.
- (f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.13.1.9. Financial Assurance.

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy. The ISO and the NEPOOL Budget and Finance Subcommittee shall reconsider these financial assurance requirements no later than five years after the first Forward Capacity Auction is conducted.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Generating Capacity Resources) and New Demand Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the financial assurance deposit specified in the ISO New England Financial Assurance Policy by the Project Sponsor for a New Generating Capacity Resource or New Demand Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Resource in the Forward Capacity Auction at the starting price. If this financial assurance deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit shall be applied toward the resource's financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit will be returned pursuant to the terms of the ISO New England Financial Assurance Policy.

III.13.1.9.2. Financial Assurance for New Generating Capacity Resources and New Demand Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Resource's offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Resource: (i) fails to provide the required financial assurance on any required date for any reason; or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4(c), it shall lose its Capacity Supply Obligation (which shall then be entered by the ISO into subsequent annual reconfiguration auctions) and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. Release of Financial Assurance.

Once a New Generating Capacity Resource or New Demand Resource achieves Commercial Operation and is tested for its capacity rating, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited. Any resulting shortfall in capacity shall then be entered by the ISO into subsequent annual reconfiguration auctions.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. Forfeit of Financial Assurance.

Where any financial assurance is forfeited pursuant to the provisions of this Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to the provisions of this Section III.13 shall be used to reduce payments incurred by load in the relevant Capacity Zone to replace that capacity.

III.13.1.9.2.4. Financial Assurance for New Import Capacity Resources.

A New Import Capacity Resource that is backed by a new External Resource shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource achieves Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. Qualification Process Cost Reimbursement Deposit.

For each New Capacity Show of Interest Form and New Demand Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below (“Qualification Process Cost Reimbursement Deposit”). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and

reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project's critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22 or 23 of the OATT or where a resource modification does not require a revision to the Interconnection Agreement.

New Generating Resources ≥ 20 MW	New Generating Resources < 20 MW and ≥ 2 MW	Imports and New Demand Resources (including Distributed Generation)		New Generating Resources < 2 MW
<i>Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources</i>	<i>Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources</i>			
\$25,000	\$7,500	\$1,000		\$500
<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>	<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>			
\$15,000	\$6500	n/a		n/a

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for Commercial Operation, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s) associated with the qualification process and critical path schedule monitoring, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring exceed the Qualification Process Cost

Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO's consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
For all resources except Demand Resources, Nov. 1, 2006 through Jan. 2, 2007 For Demand Resources, Dec. 18, 2006 through Feb. 28, 2007	Apr. 30, 2007	June 15, 2007	Feb. 4, 2008	June 1, 2010
Sept. 18, 2007 through Nov. 14, 2007	Mar. 14, 2008	Apr. 29, 2008	Dec. 8, 2008	June 1, 2011
July 15, 2008 through Sep. 16, 2008	Feb. 3, 2009	Feb. 17, 2009	Oct. 5, 2009	June 1, 2012
May 15, 2009 through July 14, 2009	Dec. 1, 2009	Dec. 15, 2009	Aug. 2, 2010	June 1, 2013
Mar. 15, 2010 through May 14, 2010	Oct. 1, 2010	Oct. 15, 2010	June 6, 2011	June 1, 2014
Mar. 1, 2011 through Mar. 14, 2011	Aug. 1, 2011	Aug. 15, 2011	Apr. 2, 2012	June 1, 2015
Jan. 3, 2012 through Jan. 17, 2012	June 1, 2012	June 15, 2012	Feb. 4, 2013	June 1, 2016
Feb. 14, 2013 through Feb. 28, 2013	June 3, 2013	June 17, 2013	Feb. 3, 2014	June 1, 2017

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

- (a) each Capacity Commitment Period shall begin in June;
- (b) the New Capacity Show of Interest Submission Window will be in February (after the Forward Capacity Auction for the prior Capacity Commitment Period), approximately four years and three months before the beginning of the Capacity Commitment Period;
- (c) the Existing Capacity Qualification Deadline will be in June just over four years before the beginning of the Capacity Commitment Period;
- (d) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and
- (e) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

The table below shows this generic timeline for the Capacity Commitment Period beginning in year “X”, where X is any year after 2015.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
Feb. (X-4)	June (X-4)	June/July (X-4)	Feb. (X-3)	June X

III.13.2. 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 Purchased~~ 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 pursuant to Section III.13.2.3.3.

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

~~Each Forward Capacity Auction shall procure one hundred percent of the Installed Capacity Requirement (net of HQICCs) approved by the Commission for the associated Capacity Commitment Period, except as a result of the Capacity Rationing Rule, as described in Sections III.13.2.6 and III.13.2.7.4. The sum of the Hydro-Quebec Interconnection Capability Credits and import capacity purchased over the Phase I/II HVDC-TF interconnection shall not exceed the capacity transfer limit of those facilities, as determined by the ISO.~~

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, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit an offer (a “New Capacity Offer”) indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource (in the associated modeled Capacity Zone during the qualification process) 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 associated modeled 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. Such 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, a New Import Capacity Resource, 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, \dots, p_m , where $P_S > p_1 > p_2 > \dots > p_m \geq P_E$, and let the associated quantities submitted for a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource be q_1, q_2, \dots, 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:

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

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) [Reserved.]

(v) A New Generating Capacity Resource (except a Renewable Technology Resource), New Import Capacity Resource, or New Demand 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.

(b) **Bids from Existing Capacity Resources Accepted in Qualification.** Static De-List Bids, Permanent De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources submitted and accepted in the qualification process (or as directed by the Commission) shall be automatically bid into the appropriate round(s) of the Forward Capacity Auction, such that each such resource's ~~summer-Qualified Capacity~~ 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, 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. 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).

(c) **Existing Capacity Resources Not Having Accepted De-List or Export Bids and Self-Supplied FCA Resources.** Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource that did not submit a Static De-List Bid, a Permanent De-List Bid, an Export Bid, or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, or an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource that did not have any such bid accepted in the qualification process, 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~~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 Generating Capacity Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity 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 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). An offer from at most one resource at a Conditional Qualified New Generating Capacity 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 Generating Capacity Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Generating Capacity 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 Generating Capacity 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 Generating Capacity 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 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 (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 (for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of the amount of capacity offered in the Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources) or the Capacity Zone's Maximum Capacity Limit) plus (for each interface between the New England Control Area and an external Control Area, the lesser of that interface's approved capacity transfer limit (net of tie benefits) or 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 Capacity Zone's Local Sourcing Requirement; or

(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~~Installed Capacity Requirement (net of HQICCs)~~;

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, 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~~the Installed Capacity Requirement (net of HQICCs)~~) and the quantity of capacity 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, if 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~~Installed Capacity Requirement (net of HQICCs)~~, 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~~Installed Capacity Requirement (net of HQICCs)~~, subject to the other provisions of this Section III.13.2. If the Total System Capacity exceeds

the amount of capacity determined by the System-Wide Capacity Demand Curve - Installed Capacity Requirement (net of HQICCs) 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 - Installed Capacity Requirement (net of HQICCs)) and 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) 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 the Capacity Zone's Maximum Capacity Limit; and

(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 - Installed Capacity Requirement (net of HQICCs);

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, 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 - Installed Capacity Requirement) and the quantity of excess supply in the export-constrained Capacity Zone (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the Maximum Capacity Limit of the export-constrained Capacity Zone) and the quantity of capacity 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 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-Installed Capacity Requirement (net of HQICCs). 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)) 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. The acceptance of a Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, or Permanent De-list Bid shall be 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].~~for each Capacity Zone in the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2016 shall be \$15/kW-month. Thereafter, the Forward Capacity Auction Starting Price will be adjusted after each Forward Capacity Auction using a rolling three-year average of the Handy-Whitman Index of Public Utility Construction Costs.~~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. 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 Generating Capacity 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 Generating Capacity 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.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent 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.

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. Bids Rejected for Reliability Reasons.

The ISO shall review each Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid entered into the Forward Capacity Auction to determine whether the capacity associated with that Non-Price Retirement Request or de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction. 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 ~~(or their successors)~~ criteria, or ISO New England System Rules. Non-Price Retirement Requests and de-list bids shall only not 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 Non-Price Retirement Request or de-list bid may

result in the procurement of less capacity than the ~~Installed Capacity Requirement (net of HQICCs)~~ or Local Sourcing Requirement for Load Zones or aggregations of Load Zones considered for modeling in a Forward Capacity Auction. Where a Non-Price Retirement Request would otherwise be accepted, or a 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 Non-Price Retirement Request or 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 and the Non-Price Retirement Request will not be approved as described in Section III.13.1.2.3.1.5.3, and the following provisions will apply:

(a) 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.

(i) In the case of Non-Price Retirement Request, the Lead Market Participant will be notified whether or not the request has been rejected for reliability reasons within 90 days of the submission of the request.

(b) A resource that has a de-list bid rejected pursuant to this Section III.13.2.5.2.5 shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1. An Existing Generating Capacity Resource or Existing Demand Resource that has a Non-Price Retirement Request rejected pursuant to this Section III.13.2.5.2.5 shall have the option to retire pursuant to Section III.2.5.2.5.3(a)(iii) or to continue operation and be compensated pursuant to Section III.13.2.5.2.5.1. A resource receiving payment under

this Section III.13.2.5.2.5 and Section III.13.2.5.2.5.1 shall have ~~the obligations of resources with Capacity Supply Obligations as described in Section III.13.6.1. Such resources shall be counted towards the Installed Capacity Requirement (net of HQICCs) for the Capacity Commitment Period.~~

(c) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which prevented the de-listing of the resource 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).

(d) If the reliability need that prevented the de-listing of the resource is met through a reconfiguration auction or other means, the resource shall be de-listed, be relieved of its Capacity Supply Obligation and no longer be eligible to receive the compensation specified in Section III.13.2.5.2.5(b). The ISO shall enter bids at the Forward Capacity Auction Starting Price to replace the capacity on behalf of load in subsequent annual reconfiguration auctions associated with the Capacity Commitment Period (and subsequent Capacity Commitment Periods, in the case of a Permanent De-List Bid).

(e) If a Permanent De-List Bid that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request is rejected for reliability reasons, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Generating 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 until such time as it is no longer needed for reliability reasons.

(f) [Reserved.]

(g) The ISO shall review with the Reliability Committee (i) the status of any prior rejected delist bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Non-Price Retirement Request 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 an identified reliability need results in the rejection of a Non-Price Retirement Request, or the rejection of a 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. For de-list bids, this review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2. System needs associated with Non-Price Retirement Requests that are rejected for reliability reasons will be reviewed with the Reliability Committee prior to the notification of the Lead Market Participant that has submitted the Non-Price Retirement Request consistent with Section 13.2.5.2.5(a)(i).

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

(a)(i) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, or partial Permanent De-List Bid would otherwise clear in the Forward Capacity Auction but the de-list bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(a)(ii), 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.

(a)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(a)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the de-list bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(a)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the de-list bid was rejected.

(b)(i) In cases where a Permanent De-List Bid for the capacity of an entire resource would otherwise clear in the Forward Capacity Auction but the Permanent De-List Bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(b)(ii), 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 de-list bid as accepted for the Forward Capacity Auction 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 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 Permanent De-List Bid as accepted for the Forward Capacity Auction. 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 was submitted. Resources that elect payment based on the accepted Permanent De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent 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 was originally submitted.

(b)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(b)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Permanent De-List Bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(b)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the Permanent De-List Bid was rejected. 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 was rejected, payment pursuant to Section III.13.2.5.2.5.1(b)(i) will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(c)(i) In cases where a Non-Price Retirement Request for less than the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource will continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability. In cases where a Non-Price Retirement Request for the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource may elect to either (i) continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability, or (ii) the resource may elect to receive cost-of-service compensation 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 Non-Price Retirement Request rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid in the same manner as other listed capacity resources. 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 subject to refund while the rate is reviewed. In no event will compensation under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Non-Price Retirement Request was rejected.

(c)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(c)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request was rejected. Once qualified under this Section III.13.2.5.2.5.1(c)(ii), compensation will be provided for the 12-month Capacity Commitment Period for which the Non-Price Retirement Request was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Non-Price Retirement Request was rejected, payment pursuant to Section III.13.2.5.2.5.1 will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(d) 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.

(e) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability.** If a Static De-List Bid or Permanent 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 Non-Price Retirement Request Resources:

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Non-Price Retirement Request for the entire resource rejected for reliability reasons pursuant to Section III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), 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 ~~New~~

England: 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(c), 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 of Resources

(a)(i) A resource, or portion thereof, that submits a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 will be retired coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted if the request is approved, or if not approved the resource nonetheless elects to retire pursuant to Section III.13.2.5.2.5.3(a)(iii). If the Non-Price Retirement Request is approved after the resource has a Capacity Supply Obligation for the Capacity Commitment Period for which the Non-Price Retirement Request was submitted, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation under Section III.13.2.5.2.5.1(c)(ii). 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) An Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-Price Retirement Request may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Non-Price Retirement Request has been approved 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.

(a)(iii) In cases where an Existing Generating Capacity Resource or Existing Demand Resource has submitted a Non-Price Retirement Request and the request is not approved because the resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, the portion of the resource subject to the Non-Price Retirement Request may nonetheless retire as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted by notifying ISO within six months of receiving the notice from the ISO that the Non-Price Retirement Request has not been approved for reliability reasons. Such an election will be binding. A resource making an election pursuant to this Section III.13.2.5.2.5.3(a)(iii) will not be

eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or 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.

(b)(i) A resource that has submitted a non-partial Permanent De-List Bid that has cleared in the Forward Capacity Auction may retire the resource as of the Capacity Commitment Period for which its Permanent De-List Bid has cleared or earlier as described in Section III.13.2.5.2.5.3(b)(ii) 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.

(b)(ii) A resource with a cleared non-partial Permanent De-List Bid may retire the resource earlier than the Capacity Commitment Period for which its Permanent De-List Bid has cleared 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. A resource electing to retire pursuant to this provision must notify ISO in writing of its election to retire and the date of retirement. The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date on retirement.

(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 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 ~~Installed Capacity Requirement (net of HQICCs)~~ or Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices) and shall be included in subsequent annual reconfiguration auctions (that is, the amount of capacity procured in subsequent annual reconfiguration auctions shall be increased by the amount of the de-listed or exported capacity).

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources and Existing Import Capacity Resources, 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 are subject to rationing, except 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.

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 a Capacity Zone at the precise amount of capacity 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 Generating Capacity 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) ~~The auctioneer shall clear the resources in such a manner as to maximize the total amount of capacity procured.~~ [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 Generating Capacity Resource's location or the offer associated with the Conditional Qualified New Generating Capacity 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 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 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~~ ~~the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1~~; 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~~ ~~Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1~~.

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 ~~the~~ 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), minus capacity otherwise obligated in the Capacity Zone for the Capacity Commitment Period. ~~system-wide “New Capacity Required” shall mean the Installed Capacity Requirement (net of HQICCs), minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated 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 ~~\$7.025/kW-month~~ 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) In an import-constrained Capacity Zone having Inadequate Supply, the difference between the amount of capacity offered in the Capacity Zone through New Capacity Offers and the amount of New Capacity Required in that Capacity Zone shall be included in subsequent annual reconfiguration auctions.

(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. System-Wide Inadequate Supply [Reserved].

~~The New England Control Area will be considered to have system wide Inadequate Supply if at the Forward Capacity Auction Starting Prices, the total amount of capacity offered in the Forward Capacity Auction is less than the Installed Capacity Requirement (net of HQICCs).~~

~~(a) In the case of system wide Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources 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 \$7.025/kW-month during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction 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) In the case of system wide Inadequate Supply, the difference between the total amount of capacity offered in the Forward Capacity Auction and the Installed Capacity Requirement (net of HQICCs) shall be included in subsequent annual reconfiguration auctions.~~

~~(c) System wide Inadequate Supply will not affect the Forward Capacity Auction in Capacity Zones having adequate supply, except that in those Capacity Zones having adequate supply, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources 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, will be paid the lower of: (1) the Capacity Clearing Price; or (2) \$7.025/kW-month.~~

~~(d) If there is system-wide Inadequate Supply, but the amount of capacity offered in an export-constrained Capacity Zone, including imports as appropriate, is greater than the Maximum Capacity Limit in that export-constrained Capacity Zone, the Forward Capacity Auction in the export-constrained Capacity Zone shall be unaffected, and in that case the price paid to Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest of Pool Capacity Zone shall be the higher of: (1) \$7.025/kW-month; or (2) the price in the export-constrained Capacity Zone.~~

III.13.2.8.2. Insufficient Competition.

The Forward Capacity Auction shall be considered to have Insufficient Competition ~~system-wide or in any~~ import-constrained Capacity Zone if there is not Inadequate Supply ~~(system-wide or in any import-constrained Capacity Zone, respectively)~~ 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), minus capacity otherwise obligated for the Capacity Commitment Period, is less than the ~~Installed Capacity Requirement (net of HQICCs) or the~~ Local Sourcing Requirement, ~~as applicable~~; 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 ~~Installed Capacity Requirement (net of HQICCs) or the~~ Local Sourcing Requirement, ~~as applicable.~~

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] \$7.025/kW-month~~ during the associated Capacity Commitment Period. 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 a rate equal to the lower of: (1) the Capacity Clearing Price; or (2) \$7.025/kW-month.

III.13.2.9. **[Reserved.]**

III.13.4. Reconfiguration Auctions.

For each Capacity Commitment Period that begins prior to June 1, 2018, 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 internal and external transmission limits and regional and local sourcing requirements updated using a methodology that is consistent with the Forward Capacity Auction) 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.

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 Non-Price Retirement Request 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 Qualification 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(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.13.1.1.2 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. 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 Qualification 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.13.4.2.1.2.1.2(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(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 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 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 determine whether the capacity associated with supply offers that would otherwise clear in a reconfiguration auction will result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the 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 determine whether the capacity associated with demand bids that would otherwise clear in a reconfiguration auction is needed to avoid a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction. 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) (including Local Sourcing Requirements and Maximum Capacity Limits for Capacity Zones for which price separation occurred in the Forward Capacity Auction for that Capacity Commitment Period) for the associated Capacity Commitment Period, to procure capacity not purchased in the Forward Capacity Auction as a result of Inadequate Supply, 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 interface transfer limits, as follows:

(a) 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 interface transfer 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. No later than 10 Business Days prior to the start of each annual reconfiguration auction, the ISO shall provide notice regarding whether the ISO will be submitting supply offers or demand bids in that auction.

(b) Any demand bid submitted by the ISO in an annual reconfiguration auction shall be at the Forward Capacity Auction Starting Price.

(c) 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.

(d) 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.

(e) 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.

(f) 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.13.6.2.1.1.

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.

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.

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.

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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.

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

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.

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 Capacity Price Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.8 of Market Rule 1.

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

Alternative Technologies Regulation Pilot Program is the pilot described in Appendix J to Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Average Hourly Output is either: (i) the sum of the Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure

consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

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

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 the day); (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, 2017, 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.

Cancellation Fee is defined in Section III.1.10.2(d).

Cancelled Start Credit is a credit calculated pursuant to Section III.F.2.5 of Appendix F to Market Rule 1 as the NCPC Credit due to each Market Participant for pool-scheduled generating Resources that were scheduled by the ISO to start after the close of the Day-Ahead Energy Market and that were cancelled by the ISO prior to their assigned commitment time.

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 January 17, 2014.

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

Capacity Carried Forward Due to Rationing is described in Section III.13.2.7.8.2.1(c)(b)(ii) of Market Rule 1.

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 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 January 17, 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 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-to-Service Ratio is defined in Section III.3.2.2(h) of Market Rule 1.

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

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

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

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

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

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

Carried Forward Excess Capacity is calculated as described in Section III.13.2.7.8.2.1(c) of Market Rule 1.

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.

Cold Weather Conditions means any calendar day when that day's Effective Temperatures are forecast to be equal to or less than zero degrees Fahrenheit for any single on-peak hour and that day's total Effective Heating Degree Days are forecast to be greater than or equal to 65.

Cold Weather Event means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than or equal to 0 MW for an Operating Day. Cold Weather Events are declared by 1100 two days prior to the Operating Day. A Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists, until such time that the ISO declares a Cold Weather Event.

Cold Weather Warning means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than 1,000 MW. In addition, a Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists for days not yet declared as a Cold Weather Event.

Cold Weather Watch means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin greater than or equal to 1,000 MW.

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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2017, 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, 2017.

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 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, 2017, 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 the electricity consumption of an individual end-use customer at a Retail Delivery Point or the aggregated electricity consumption of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2.

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 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, 2017.

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 Resource's or contract's Supply Offer or Demand Bid 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 level of each generating Resource and each Dispatchable Asset Related Demand and each Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

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

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

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

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

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

Distributed Generation means generation resources directly connected to end-use customer load and located behind the end-use customer's meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

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

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

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at or 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 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 the maximum of the following values: (i) the Emergency Minimum Limit; (ii) a level supported by environmental and/or operating permit restrictions; or (iii) a level that addresses any significant economic penalties associated with operating at lower levels that can not be adequately represented by three part bidding (Start-Up Fee, No-Load Fee and incremental energy price). In no event shall the Economic Minimum Limit submitted as part of a generating unit's Offer Data be higher than the generation level at which a generating unit's incremental heat rate is minimized (i.e., transitioning from decreasing as output increases to increasing as output increases) except that a Self-Scheduled Resource may modify its Economic Minimum Limit on an hourly basis, as part of its Supply Offer, in order to indicate the desired level of Self-Scheduled MWs.

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

EFT is electronic funds transfer.

Effective Heating Degree Days is equal to $68 - (\text{average of max and min Effective Temperature of the day})$.

Effective Temperature is equal to $\text{dry bulb temperature} - [\text{windspeed} \times (65 - \text{dry bulb temp}) / 100]$.

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.5 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

Elective Transmission Upgrade Applicant is defined in Section II.47.5 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, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II 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 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.

Exempt Real-Time Generation Obligation means that portion of a Market Participant's Real-Time Generation Obligation that is not included in the calculation of Minimum Generation Emergency Credits pursuant to Appendix F of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

External 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.

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 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) time to start does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

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

Governance Participant is defined in the Participants Agreement.

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

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

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

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

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

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

OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

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

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

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

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

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

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

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

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

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 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Agreement is the “Large Generator Interconnection Agreement” or the “Small Generator Interconnection Agreement” pursuant to Schedules 22 and 23 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 and Attachment 1 to Schedule 23 of the OATT.

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

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

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

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

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

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

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

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted

Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal 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 or Demand Bids 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 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 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, 2017, 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, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

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

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

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

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

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

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

LSE means load serving entity.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or

exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

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

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

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

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

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

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

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

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

Measure Life is the estimated time a Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the Demand Reduction Value of the Demand Resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the Demand Reduction Value for an Existing Demand Resource is not overstated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

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

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

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

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

MEPCO Grandfathered Transmission Service Agreement (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 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 Charge means the charge used to allocate the cost of Minimum Generation Emergency Credits. Minimum Generation Emergency Charges are discussed in Appendix F of Market Rule 1.

Minimum Generation Emergency Credits are credits calculated pursuant to Appendix F of Market Rule 1 to compensate certain generating Resources for operation in excess of their Economic Minimum Limits during a Minimum Generation Emergency.

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 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 MWs.

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 MWs.

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

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

MUI is the market user interface.

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

MW is megawatt.

MWh is megawatt-hour.

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

NCPC Charge means the charges to Market Participants as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

NCPC Credit means the payment made to a Resource as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

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.

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 Generator Asset is the Generator Asset registered in the energy market at the same Retail Delivery Point as a Demand Response Asset with Distributed Generation capable of delivering Net Supply.

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

Network Customer is a Transmission Customer receiving RNS or LNS.

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, as described in Section III.13.2.3.2 of Market Rule 1.

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.

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

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

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

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

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

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

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

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

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

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission.

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, 2017, 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, 2017.

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 a Supply Offer value between 0 and the CLAIM10 of a Resource that represents the amount of TMNSR available from the Resource.

Offered CLAIM30 is a Supply Offer value between 0 and the CLAIM30 of a Resource that represents the amount of offline TMOR available from the Resource.

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

On-Peak Demand Resource is a type of Demand Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

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

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

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

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

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

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

Operations Date is February 1, 2005.

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

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

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as

adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability.

Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

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

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 Credit is calculated pursuant to Section III.F.2.6.2 of Appendix F to Market Rule 1.

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 or New Demand Resource participate in the Forward Capacity Market, as described in Section III.13.

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

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

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.

Queue Position has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 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 Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

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, 2017, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2017.

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 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 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 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 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.5.6.1 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 generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

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 Capability (REGCAP) means the amount of Regulation capability available on a Market Participant's Resource as calculated by the ISO based upon that Resource's Automatic Response Rate and the available regulating range as specified in ISO New England Manual 11 – Market Operations.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.

Regulation Rank Price is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

Regulation Requirement is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

Regulation Service Credit is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

Regulation Service Megawatts are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

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 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, 2017, 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 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, 2017, a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

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 and/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. 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 the greater of: (i) the Resource's Economic Minimum Limit; or (ii) the Resource's Minimum Consumption Limit; or (iii) for a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was

on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.

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.

Seven-Day Forecast has the meaning specified in Section III.H.3.3(a).

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).

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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

Start-Up Fee is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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

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

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

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. The daily bid Blocks in the price-based Real-Time offer/bid will be multiplied by the number of hours in the day 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, or Schedule 23 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 a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

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 a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, and is provided by generating units and Dispatchable Asset Related Demand pumps 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 a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

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.

Time-on-Regulation Credit is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

Time-on-Regulation Megawatts is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

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 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.

Table of Contents

III.1	Market Operations	
III.1.1	Introduction.	
III.1.2	[Reserved.]	
III.1.3	Definitions.	
III.1.3.1	[Reserved.]	
III.1.3.2	[Reserved.]	
III.1.3.3	[Reserved.]	
III.1.4	Requirements for Certain Transactions.	
III.1.4.1	ISO Settlement of Certain Transactions.	
III.1.4.2	Transactions Subject to Requirements of Section III.1.4.	
III.1.4.3	Requirements for Section III.1.4 Conforming Transactions.	
III.1.5	Resource Auditing.	
III.1.5.1.	Claimed Capability Audits.	
III.1.5.1.1.	General Audit Requirements.	
III.1.5.1.2.	Establish Claimed Capability Audit.	
III.1.5.1.3.	Seasonal Claimed Capability Audits.	
III.1.5.1.4.	ISO-Initiated Claimed Capability Audits.	
III.1.5.2.	ISO-Initiated Parameter Auditing.	
III.1.6	[Reserved.]	
III.1.6.1	[Reserved.]	
III.1.6.2	[Reserved.]	
III.1.6.3	[Reserved.]	
III.1.6.4	ISO New England Manuals and ISO New England Administrative Procedures.	
III.1.7	General.	
III.1.7.1	Provision of Market Data to the Commission.	
III.1.7.2	[Reserved.]	

III.1.7.3	Agents.
III.1.7.4	[Reserved.]
III.1.7.5	[Reserved.]
III.1.7.6	Scheduling and Dispatching.
III.1.7.7	Energy Pricing.
III.1.7.8	Market Participant Resources.
III.1.7.9	Real-Time Reserve Prices.
III.1.7.10	Other Transactions.
III.1.7.11	Seasonal Claimed Capability of A Generating Capacity Resource.
III.1.7.12	[Reserved.]
III.1.7.13	[Reserved.]
III.1.7.14	[Reserved.]
III.1.7.15	[Reserved.]
III.1.7.16	[Reserved.]
III.1.7.17	Operating Reserve.
III.1.7.18	Regulation.
III.1.7.19	Ramping.
III.1.7.19A	Real-Time Reserve.
III.1.7.20	Information and Operating Requirements.
III.1.8	[Reserved.]
III.1.9	Pre-scheduling.
III.1.9.1	[Reserved.]
III.1.9.2	[Reserved.]
III.1.9.3	[Reserved.]
III.1.9.4	[Reserved.]
III.1.9.5	[Reserved.]
III.1.9.6	[Reserved.]
III.1.9.7	Market Participant Responsibilities.

III.1.9.8	[Reserved.]
III.1.10	Scheduling.
III.1.10.1	General.
III.1.10.1A	Day Ahead Energy Market Scheduling.
III.1.10.2	Pool Scheduled Resources.
III.1.10.3	Self-Scheduled Resources.
III.1.10.4	[Reserved.]
III.1.10.5	External Resources.
III.1.10.6	Dispatchable Asset Related Demand Resources.
III.1.10.7	External Transactions.
III.1.10.8	ISO Responsibilities.
III.1.10.9	Hourly Scheduling.
III.1.11	Dispatch.
III.1.11.1	Resource Output.
III.1.11.2	Operating Basis.
III.1.11.3	Pool-dispatched Resources.
III.1.11.4	Emergency Condition.
III.1.11.5	Regulation.
III.1.11.6	[Reserved.]
III.1.12	Dynamic Scheduling.
III.2	LMPs and Real-Time Reserve Clearing Prices Calculation
III.2.1	Introduction.
III.2.2	General.
III.2.3	Determination of System Conditions Using the State Estimator.
III.2.4	Determination of Energy Offers Used in Calculating Real-Time Prices and Real-Time Reserve Clearing Prices.
III.2.5	Calculation of Real-Time Nodal Prices.
III.2.6	Calculation of Day-Ahead Nodal Prices.

- III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.
- III.2.7A Calculation of Real-Time Reserve Clearing Prices.
- III.2.8 Hubs and Hub Prices.
- III.2.9A Final Real-Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.
- III.2.9B Final Day-Ahead Energy Market Results.
- III.3 Accounting And Billing
 - III.3.1 Introduction.
 - III.3.2 Market Participants.
 - III.3.2.1 ISO Energy Market.
 - III.3.2.2 Regulation.
 - III.3.2.3 NCPC Credits.
 - III.3.2.4 Transmission Congestion.
 - III.3.2.5 [Reserved.]
 - III.3.2.6 Emergency Energy.
 - III.3.2.6A New Brunswick Security Energy.
 - III.3.2.7 Billing.
 - III.3.3 [Reserved.]
 - III.3.4 Non-Market Participant Transmission Customers.
 - III.3.4.1 Transmission Congestion.
 - III.3.4.2 Transmission Losses.
 - III.3.4.3 Billing.
 - III.3.5 [Reserved.]
 - III.3.6 Data Reconciliation.
 - III.3.6.1 Data Correction Billing.
 - III.3.6.2 Eligible Data.
 - III.3.6.3 Data Revisions.
 - III.3.6.4 Meter Corrections Between Control Areas.

- III.3.6.5 Meter Correction Data.
 - III.3.7 Eligibility for Billing Adjustments.
 - III.3.8 Correction of Meter Data Errors.
 - III.4 Rate Table
 - III.4.1 Offered Price Rates.
 - III.4.2 [Reserved.]
 - III.4.3 Emergency Energy Transaction.
 - III.5 Transmission Congestion Revenue & Credits Calculation
 - III.5.1 Non-Market Participant Transmission Congestion Cost Calculation
 - III.5.1.1 Calculation by ISO.
 - III.5.1.2 General.
 - III.5.1.3 [Reserved.]
 - III.5.1.4 Non-Market Participant Transmission Customer Calculation.
 - III.5.2 Transmission Congestion Credit Calculation.
 - III.5.2.1 Eligibility.
 - III.5.2.2 Financial Transmission Rights.
 - III.5.2.3 [Reserved.]
 - III.5.2.4 Target Allocation to FTR Holders.
 - III.5.2.5 Calculation of Transmission Congestion Credits.
 - III.5.2.6 Distribution of Excess Congestion Revenue.
 - III.6 Local Second Contingency Protection Resources
 - III.6.1 [Reserved.]
 - III.6.2 Day-Ahead and Real-Time Energy Market.
 - III.6.2.1 Special Constraint Resources.
 - III.6.3 [Reserved.]
 - III.6.4 Local Second Contingency Protection Resource NCPC Charges.
 - III.6.4.1 [Reserved.]
 - III.6.4.2 [Reserved.]

III.6.4.3 Calculation of Local Second Contingency Protection Resource
NCPC Payments.

III.7 Financial Transmission Rights Auctions

III.7.1 Auctions of Financial Transmission Rights.

III.7.1.1 Auction Period and Scope of Auctions.

III.7.1.2 FTR Auctions Assumptions.

III.7.2 Financial Transmission Rights Characteristics.

III.7.2.1 Reconfiguration of Financial Transmission Rights.

III.7.2.2 Specified Locations.

III.7.2.3 Transmission Congestion Revenues.

III.7.2.4 [Reserved.]

III.7.3 Auction Procedures.

III.7.3.1 Role of the ISO.

III.7.3.2 [Reserved.]

III.7.3.3 [Reserved.]

III.7.3.4 On-Peak and Off-Peak Periods.

III.7.3.5 Offers and Bids.

III.7.3.6 Determination of Winning Bids and Clearing Price.

III.7.3.7 Announcement of Winners and Prices.

III.7.3.8 Auction Settlements.

III.7.3.9 Allocation of Auction Revenues.

III.7.3.10 Simultaneous Feasibility.

III.7.3.11 [Reserved.]

III.7.3.12 Financial Transmission Rights in the Form of Options.

III.8A. Demand Response Baselines

III.8A.1. Establishing the Initial Demand Response Baseline.

III.8A.2. Establishing the Demand Response Baseline for the Next Day.

III.8A.3. Determining if Meter Data From the Present Day is Used in the Demand
Response Baseline for the Next Day.

III.8A.4. Baseline Adjustment.

III.8A.4.1. Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets Without Generation or From Real-Time Emergency Generation Assets Without Additional Generation.

III.8A.4.2. Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets with Generation or From Real-Time Emergency Generation Assets With Additional Generation.

III.8A.4.3. Baseline Adjustment for Real-Time Demand Reductions Produced By Directly Metered Generation.

III.8B. Demand Response Baselines.

III.8B.1. Demand Response Baseline Calculations,

III.8B.1.1. Demand Response Baseline Real-Time Emergency Generation Asset Adjustment.

III.8B.2. Establishing an Initial Demand Response Baseline.

III.8B.3. Establishing a Demand Response Baseline for the Next Day.

III.8B.4. Determining if Meter Data from the Present Day is Used in the Demand Response Baseline for the Next Day of the Same Day Type.

III.8B.5. Baseline Adjustment.

III.9 Forward Reserve Market

III.9.1 Forward Reserve Market Timing.

III.9.2 Forward Reserve Market Reserve Requirements.

III.9.2.1 Forward Reserve Market Minimum Reserve Requirements.

III.9.2.2 Locational Reserve Requirements for Reserve Zones.

III.9.3 Forward Reserve Auction Offers.

III.9.4 Forward Reserve Auction Clearing and Forward Reserve Clearing Prices.

III.9.4.1 Forward Reserve Clearing Price and Forward Reserve Obligation Publication and Correction.

III.9.5. Forward Reserve Resources

III.9.5.1 Assignment of Forward Reserve MWs to Forward Reserve Resources.

III.9.5.2 Forward Reserve Resource Eligibility Requirements.

- III.9.5.3 Resource CLAIM10 and CLAIM30 Values.
- III.9.5.3.1. Calculating Resource CLAIM10 and CLAIM30 Values.
- III.9.5.3.2. CLAIM10 and CLAIM 30 Audits.
- III.9.5.3.3. CLAIM10 and CLAIM30 Performance Factors.
- III.9.5.3.4. Performance Factor Cure.
- III.9.6 Delivery of Reserve.
 - III.9.6.1 Dispatch and Energy Bidding of Reserve.
 - III.9.6.2 Forward Reserve Threshold Prices.
 - III.9.6.3 Monitoring of Forward Reserve Resources.
 - III.9.6.4 Forward Reserve Qualifying Megawatts.
 - III.9.6.5 Delivery Accounting.
- III.9.7 Consequences of Delivery Failure.
 - III.9.7.1 Real-Time Failure-to-Reserve.
 - III.9.7.2 Failure-to-Activate Penalties.
 - III.9.7.3 Known Performance Limitations.
- III.9.8 Forward Reserve Credits.
- III.9.9 Forward Reserve Charges.
 - III.9.9.1 Forward Reserve Credits Associated with System Reserve Requirements.
 - III.9.9.2 Adjusting Forward Reserve Credits for System Requirements.
 - III.9.9.3 Allocating Forward Reserve Credits for System Requirements.
 - III.9.9.4 Allocating Remaining Forward Reserve Credits.
 - III.9.9.4.1 Allocation Criteria for Remaining Forward Reserve Credits.
- III.10 Real-Time Reserve
 - III.10.1 Provision of Operating Reserve in Real-Time.
 - III.10.1.1 Real-Time Reserve Designation.
 - III.10.2 Real-Time Reserve Credits.
 - III.10.3 Real-Time Reserve Charges.
 - III.10.4 Forward Reserve Obligation Charges.

- III.10.4.1 Forward Reserve Obligation Charge Megawatts for Forward Reserve Resources.
 - III.10.4.2 Forward Reserve Obligation Charge Megawatts.
 - III.10.4.3 Forward Reserve Obligation Charge.
- III.11 Gap RFPs For Reliability Purposes
 - III.11.1 Request For Proposals for Load Response and Supplemental Generation Resources for Reliability Purposes.
- III.12 Calculation of Capacity Requirements
 - III.12.1 Installed Capacity Requirement.
 - III.12.2 Local Sourcing Requirements and Maximum Capacity Limits.
 - III.12.2.1 Calculation of Local Sourcing Requirements for Import-Constrained Load Zones.
 - III.12.2.1.1 Local Reserve Adequacy Requirement.
 - III.12.2.1.2 Transmission Security Analysis Requirement.
 - III.12.2.2 Calculation of Maximum Capacity Limit for Export-Constrained Load Zones.
 - III.12.3 Consultation and Filing of Capacity Requirements.
 - III.12.4 Capacity Zones.
 - III.12.5 Transmission Interface Limits.
 - III.12.6 Modeling Assumptions for Determining the Network Model.
 - III.12.6.1 Process for Establishing the Network Model.
 - III.12.6.2 Initial Threshold to be Considered In-Service.
 - III.12.6.3 Evaluation Criteria.
 - III.12.7 Resource Modeling Assumptions.
 - III.12.7.1 Proxy Units.
 - III.12.7.2 Capacity.
 - III.12.7.2.1 [Reserved.]
 - III.12.7.3 Resource Availability.
 - III.12.7.4 Load and Capacity Relief.
 - III.12.8 Load Modeling Assumptions.

III.12.9	Tie Benefits.
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.
III.12.9.1.2.	Tie Benefits Calculation.
III.12.9.1.3.	Adjustments to Account for Transmission Import Capability and Capacity Imports.
III.12.9.2	Modeling Assumptions and Procedures for the Tie Benefits Calculation.
III.12.9.2.1.	Assumptions Regarding System Conditions.
III.12.9.2.2.	Modeling Internal Transmission Constraints in New England.
III.12.9.2.3.	Modeling Transmission Constraints in Neighboring Control Areas.
III.12.9.2.4.	Other Modeling Assumptions.
III.12.9.2.5.	Procedures for Adding or Removing Capacity from Control Areas to Meet the 0.1 Days Per Year LOLE Standard.
III.12.9.3.	Calculating Total Tie Benefits.
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.
III.12.9.4.2.	Pro Ration Based on Total Tie Benefits.
III.12.9.5.	Calculating Tie Benefits for Individual Ties.
III.12.9.5.1.	Initial Calculation of Tie Benefits for an Individual Interconnection or Group of Interconnections.
III.12.9.5.2.	Pro Ration Based on Total Tie Benefits.
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.
III.12.9.6.2.	Changes in the Import Capability of Interconnections with Neighboring Control Areas.
III.12.9.7.	Tie Benefits Over the HQ Phase I/II HVDC-TF.

- 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.
- III.13 Forward Capacity Market
 - III.13.1 Forward Capacity Auction Qualification.
 - III.13.1.1 New Generating Capacity Resources.
 - III.13.1.1.1 Definition of New Generating Capacity Resource.
 - III.13.1.1.1.1 Resources Never Previously Counted as Capacity.
 - III.13.1.1.1.2 Resources Previously Counted as Capacity.
 - III.13.1.1.1.3 Incremental Capacity of Resources Previously Counted as Capacity.
 - III.13.1.1.1.4 De-rated Capacity of Resources Previously Counted as Capacity.
 - III.13.1.1.1.5 Treatment of Resources that are Partially New and Partially Existing.
 - III.13.1.1.1.6 Treatment of Deactivated and Retired Units.
 - III.13.1.1.1.7 Renewable Technology Resources.
 - III.13.1.1.2 Qualification Process for New Generating Capacity Resources.
 - III.13.1.1.2.1 New Capacity Show of Interest Form.
 - III.13.1.1.2.2 New Capacity Qualification Package.
 - III.13.1.1.2.2.1 Site Control.
 - III.13.1.1.2.2.2 Critical Path Schedule.
 - III.13.1.1.2.2.3 Offer Information.
 - III.13.1.1.2.2.4 Capacity Commitment Period Election.
 - III.13.1.1.2.2.5 Additional Requirements for Resources Previously Listed as Capacity.
 - III.13.1.1.2.2.6 Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.
 - III.13.1.1.2.3 Initial Interconnection Analysis.
 - III.13.1.1.2.4 Evaluation of New Capacity Qualification Package.
 - III.13.1.1.2.5 Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1	New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.
III.13.1.1.2.5.2	[Reserved.]
III.13.1.1.2.5.3	New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.
III.13.1.1.2.5.4	New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.
III.13.1.1.2.6	[Reserved.]
III.13.1.1.2.7	Opportunity to Consult with Project Sponsor.
III.13.1.1.2.8	Qualification Determination Notification for New Generating Capacity Resources.
III.13.1.1.2.9	Renewable Technology Resource Election.
III.13.1.1.2.10	Determination of Renewable Technology Resource Qualified Capacity.
III.13.1.2	Existing Generating Capacity Resources.
III.13.1.2.1	Definition of Existing Generating Capacity Resource.
III.13.1.2.2	Qualified Capacity for Existing Generating Capacity Resources.
III.13.1.2.2.1	Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.
III.13.1.2.2.1.1	Summer Qualified Capacity.
III.13.1.2.2.1.2	Winter Qualified Capacity.
III.13.1.2.2.2	Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.
III.13.1.2.2.2.1	Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.
III.13.1.2.2.2.2	Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.
III.13.1.2.2.3	Qualified Capacity Adjustment for Partially New and Partially Existing Resources.
III.13.1.2.2.4	Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.
III.13.1.2.2.5	Adjustment for Certain Significant Increases in Capacity.
III.13.1.2.2.5.1	[Reserved.]

III.13.1.2.2.5.2	Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.
III.13.1.2.3	Qualification Process for Existing Generating Capacity Resources.
III.13.1.2.3.1	Existing Capacity Qualification Package.
III.13.1.2.3.1.A	Dynamic De-List Bid Threshold.
III.13.1.2.3.1.1	Static De-List Bids.
III.13.1.2.3.1.2	Permanent De-List Bids.
III.13.1.2.3.1.3	Export Bids.
III.13.1.2.3.1.4	Administrative Export De-List Bids.
III.13.1.2.3.1.5	Non-Price Retirement Request.
III.13.1.2.3.1.5.1	Description of Non-Price Retirement Request.
III.13.1.2.3.1.5.2	Timing Requirements.
III.13.1.2.3.1.5.3	Reliability Review of Non-Price Retirement Requests.
III.13.1.2.3.1.5.4	Obligation to Retire.
III.13.1.2.3.1.6	Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.
III.13.1.2.3.1.6.1	Submission of Cost Data.
III 13.1.2.3.1.6.2	[Reserved.]
III 13.1.2.3.1.6.3	Internal Market Monitor Review.
III.13.1.2.3.2	Review by Internal Market Monitor of Bids Received from Existing Generating Capacity Resources.
III.13.1.2.3.2.1	Static De-List Bids, Export Bids Above the Dynamic De-List Bid Threshold, and Permanent De-List Bids Above the Dynamic De-List Bid Threshold.
III.13.1.2.3.2.1.1	Internal Market Monitor Review of De-List Bids.
III.13.1.2.3.2.1.1.1.	Review of Permanent De-List Bids and Export Bids.
III.13.1.2.3.2.1.1.2.	Review of Static De-List Bids.
III.13.1.2.3.2.1.2	Net Going Forward Costs.
III.13.1.2.3.2.1.3	Expected Capacity Performance Payments.

III.13.1.2.3.2.1.4	Risk Premium.
III.13.1.2.3.2.1.5	Opportunity Costs.
III.13.1.2.3.2.2	[Reserved.]
III.13.1.2.3.2.3	Administrative Export De-List Bids.
III.13.1.2.3.2.4	Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.
III.13.1.2.3.2.5	Incremental Capital Expenditure Recovery Schedule.
III.13.1.2.4	Qualification Determination Notification for Existing Capacity.
III.13.1.2.5	Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.
III.13.1.3	Import Capacity.
III.13.1.3.1	Definition of Existing Import Capacity Resource.
III.13.1.3.2	Qualified Capacity for Existing Import Capacity Resources.
III.13.1.3.3	Qualification Process for Existing Import Capacity Resources.
III.13.1.3.4	Definition of New Import Capacity Resource.
III.13.1.3.5	Qualification Process for New Import Capacity Resources.
III.13.1.3.5.1	Documentation of Import.
III.13.1.3.5.2	Import Backed by Existing External Resources.
III.13.1.3.5.3	Imports Backed by an External Control Area.
III.13.1.3.5.3.1	Imports Crossing Intervening Control Areas.
III.13.1.3.5.4	Capacity Commitment Period Election.
III.13.1.3.5.5	Initial Interconnection Analysis.
III.13.1.3.5.6	Review by Internal Market Monitor of Offers from New Import Capacity Resources and Existing Import Capacity Resources.
III.13.1.3.5.7	Qualification Determination Notification for New Import Capacity Resources.
III.13.1.3.5.8	Rationing Election.
III.13.1.4	Demand Resources.
III.13.1.4.1	Demand Resources.
III.13.1.4.1.1	Existing Demand Resources.

III.13.1.4.1.2	New Demand Resources.
III.13.1.4.1.2.1	Qualified Capacity of New Demand Resources.
III.13.1.4.1.2.2	Initial Analysis of Certain New Demand Resources.
III.13.1.4.1.3	Special Provisions for Real-Time Emergency Generation Resources.
III.13.1.4.2	Show of Interest Form for New Demand Resources.
III.13.1.4.2.1	Qualification Package for Existing Demand Resources.
III.13.1.4.2.2	Qualification Package for New Demand Resources.
III.13.1.4.2.2.1	[Reserved.]
III.13.1.4.2.2.2	Source of Funding.
III.13.1.4.2.2.3	Measurement and Verification Plan.
III.13.1.4.2.2.4	Customer Acquisition Plan.
III.13.1.4.2.2.4.1	Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.
III.13.1.4.2.2.4.2	Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.
III.13.1.4.2.2.4.3	Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.
III.13.1.4.2.2.5	Capacity Commitment Period Election.
III.13.1.4.2.2.6	Rationing Election.
III.13.1.4.2.3	Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.
III.13.1.4.2.4	Offers from New Demand Resources.
III.13.1.4.2.5	Notification of Qualification for Demand Resources.
III.13.1.4.2.5.1	Evaluation of Demand Resource Qualification Materials.
III.13.1.4.2.5.2	Notification of Qualification for Existing Demand Resources.
III.13.1.4.2.5.3	Notification of Qualification for New Demand Resources.
III.13.1.4.2.5.3.1	Notification of Acceptance to Qualify of a New Demand Resource.

III.13.1.4.2.5.3.2	Notification of Failure to Qualify of a New Demand Resource.
III.13.1.4.3	Measurement and Verification Applicable to All Demand Resources.
III.13.1.4.3.1	Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.
III.13.1.4.3.1.1	Optional Measurement and Verification Reference Reports.
III.13.1.4.3.1.2	Updated Measurement and Verification Documents.
III.13.1.4.3.1.3	Annual Certification of Accuracy of Measurement and Verification Documents.
III.13.1.4.3.1.4.	Record Requirement of Retail Customers Served.
III.13.1.4.3.2	Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.
III.13.1.4.3.2.1.	No Performance Data to Determine Demand Reduction Values.
III.13.1.4.3.3.	ISO Review of Measurement and Verification Documents.
III.13.1.4.3.4.	Measurement and Verification Costs.
III.13.1.4.4	Dispatch of Active Demand Resources During Event Hours.
III.13.1.4.4.1	Notification of Demand Resource Forecast Peak Hours.
III.13.1.4.4.2	Dispatch of Demand Resources during Real-Time Demand Resource Dispatch Hours.
III.13.1.4.4.3	Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.
III.13.1.4.5	Selection of Active Demand Resources For Dispatch.
III.13.1.4.5.1	Management of Real-Time Demand Response Assets and Real-Time Demand Response Resources.
III.13.1.4.5.2	Management of Real-Time Emergency Generation Assets and Real-Time Emergency Generation Resources.
III.13.1.4.5.3	[Reserved.]
III.13.1.4.6	Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at Dispatch Zones.
III.13.1.4.6.1	Establishment of Dispatch Zones.
III.13.1.4.6.2	Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

III.13.1.4.6.2.1	Real-Time Demand Response Resource Disaggregation.
III.13.1.4.6.2.2	Real-Time Emergency Generation Resource Disaggregation.
III.13.1.4.7	[Reserved.]
III.13.1.4.8	[Reserved.]
III.13.1.4.9	Restrictions on Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Registration.
III.13.1.4.9.1	Requirement for Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Retirement.
III.13.1.4.10	Providing Information On Real-Time Demand Response and Real-Time Emergency Generation Resource.
III.13.1.4.11.	Assignment of Demand Assets to a Demand Resource.
III.13.1.5	Offers Composed of Separate Resources.
III.13.1.5.A.	Notification of FCA Qualified Capacity.
III.13.1.6	Self-Supplied FCA Resources.
III.13.1.6.1	Self-Supplied FCA Resource Eligibility.
III.13.1.6.2	Locational Requirement for Self-Supplied FCA Resources.
III.13.1.7	Internal Market Monitor Review of Offers and Bids.
III.13.1.8	Publication of Offer and Bid Information.
III.13.1.9	Financial Assurance.
III.13.1.9.1	Financial Assurance for New Generating Capacity Resources and New Demand Resources Participating in the Forward Capacity Auction.
III.13.1.9.2	Financial Assurance for New Generating Capacity Resources and New Demand Resources Clearing in a Forward Capacity Auction.
III.13.1.9.2.1	Failure to Provide Financial Assurance or to Meet Milestone.
III.13.1.9.2.2	Release of Financial Assurance.
III.13.1.9.2.2.1	[Reserved.]
III.13.1.9.2.3	Forfeit of Financial Assurance.
III.13.1.9.2.4	Financial Assurance for New Import Capacity Resources.

III.13.1.9.3	Qualification Process Cost Reimbursement Deposit.
III.13.1.9.3.1	Partial Waiver of Deposit.
III.13.1.9.3.2	Settlement of Costs.
III.13.1.9.3.2.1	Settlement of Costs Associated With Resources Participating In A Forward Capacity Auction Of Reconfiguration Auction.
III.13.1.9.3.2.2	Settlement of Costs Associated With Withdrew From A Forward Capacity Auction Of Reconfiguration Auction.
III.13.1.9.3.2.3	Crediting Of Reimbursements.
III.13.1.10	Forward Capacity Auction Qualification Schedule.
III.13.2	Annual Forward Capacity Auction.
III.13.2.1	Timing of Annual Forward Capacity Auctions.
III.13.2.2	Amount of Capacity Cleared in Each Forward Capacity Auction.
III.13.2.3	Conduct of the Forward Capacity Auction.
III.13.2.3.1	Step 1: Announcement of Start-of-Round Price and End-of-Round Price.
III.13.2.3.2	Step 2: Compilation of Offers and Bids.
III.13.2.3.3	Step 3: Determination of the Outcome of Each Round.
III.13.2.3.4	Determination of Final Capacity Zones.
III.13.2.4	Forward Capacity Auction Starting Price and the Cost of New Entry.
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.
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.
III.13.2.5.2.2	Static De-List Bids and Export Bids.
III.13.2.5.2.3	Dynamic De-List Bids.
III.13.2.5.2.4	Administrative Export De-List Bids.

III.13.2.5.2.5	Bids Rejected for Reliability Reasons.
III.13.2.5.2.5.1	Compensation for Bids Rejected for Reliability Reasons.
III.13.2.5.2.5.2	Incremental Cost of Reliability Service From Non-Price Retirement Request Resources.
III.13.2.5.2.5.3	Retirement of Resources.
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.
III.13.2.6	Capacity Rationing Rule.
III.13.2.7	Determination of Capacity Clearing Prices.
III.13.2.7.1	Import-Constrained Capacity Zone Capacity Clearing Price Floor.
III.13.2.7.2	Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.
III.13.2.7.3	Capacity Clearing Price Floor.
III.13.2.7.3A	Treatment of Imports.
III.13.2.7.4	Effect of Capacity Rationing Rule on Capacity Clearing Price.
III.13.2.7.5	Effect of Decremental Repowerings on the Capacity Clearing Price.
III.13.2.7.6	Minimum Capacity Award.
III.13.2.7.7	Tie-Breaking Rules.
III.13.2.7.8	[Reserved.]
III.13.2.7.9	Capacity Carry Forward Rule.
III.13.2.7.9.1.	Trigger.
III.13.2.7.9.2	Pricing.
III.13.2.8	Inadequate Supply and Insufficient Competition.
III.13.2.8.1	Inadequate Supply.
III.13.2.8.1.1	Inadequate Supply in an Import-Constrained Capacity Zone.
III.13.2.8.1.2	[Reserved.].
III.13.2.8.2	Insufficient Competition.
III.13.2.9	[Reserved.]

- III.13.3 Critical Path Schedule Monitoring.
 - III.13.3.1 Resources Subject to Critical Path Schedule Monitoring.
 - III.13.3.1.1 New Resources Clearing in the Forward Capacity Auction.
 - III.13.3.1.2 New Resources Not Offering or Not Clearing in the Forward Capacity Auction.
 - III.13.3.2 Quarterly Critical Path Schedule Reports.
 - III.13.3.2.1 Updated Critical Path Schedule.
 - III.13.3.2.2 Documentation of Milestones Achieved.
 - III.13.3.2.3 Additional Relevant Information.
 - III.13.3.2.4 Additional Information for Resources Previously Listed as Capacity.
 - III.13.3.3 Failure to Meet Critical Path Schedule.
 - III.13.3.4 Covering Capacity Supply Obligation where Resource will Not Achieve Commercial Operation by the Start of the Capacity Commitment Period.
 - III.13.3.5 Termination of Interconnection Agreement.
 - III.13.3.6 Withdrawal from Critical Path Schedule Monitoring.
- III.13.4 Reconfiguration Auctions.
 - III.13.4.1 Capacity Zones Included in Reconfiguration Auctions.
 - III.13.4.2 Participation in Reconfiguration Auctions.
 - III.13.4.2.1 Supply Offers.
 - III.13.4.2.1.1 Amount of Capacity That May Be Submitted in a Supply Offer in an 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.
 - III.13.4.2.1.2.1.1.2 Winter ARA Qualified Capacity.

III.13.4.2.1.2.1.2	Intermittent Power Resources.
III.13.4.2.1.2.1.2.1	Summer ARA Qualified Capacity.
III.13.4.2.1.2.1.2.2	Winter ARA Qualified Capacity.
III.13.4.2.1.2.1.3	Import Capacity Resources.
III.13.4.2.1.2.1.4	Demand Resources.
III.13.4.2.1.2.1.4.1	Summer ARA Qualified Capacity.
III.13.4.2.1.2.1.4.2	Winter ARA Qualified Capacity.
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.
III.13.4.2.1.2.2.1.2	Winter ARA Qualified Capacity.
III.13.4.2.1.2.2.2	Intermittent Power Resources.
III.13.4.2.1.2.2.2.1	Summer ARA Qualified Capacity.
III.13.4.2.1.2.2.2.2	Winter ARA Qualified Capacity.
III.13.4.2.1.2.2.2.3	Adjustment for Certain Intermittent Power Resources and Intermittent Settlement Only Resources.
III.13.4.2.1.2.2.3	Import Capacity Resources.
III.13.4.2.1.2.2.4	Demand Resources.
III.13.4.2.1.2.2.4.1	Summer ARA Qualified Capacity.
III.13.4.2.1.2.2.4.2	Winter ARA Qualified Capacity.
III.13.4.2.1.3	Adjustment for Significant Decreases in Capacity.
III.13.4.2.1.4	Amount of Capacity That May Be Submitted in a Supply Offer in a Monthly Reconfiguration Auction.
III.13.4.2.1.5	ISO Review of Supply Offers.
III.13.4.2.2	Demand Bids in Reconfiguration Auctions.
III.13.4.3	ISO Participation in Reconfiguration Auctions.
III.13.4.4	Clearing Offers and Bids in Reconfiguration Auctions.
III.13.4.5	Annual Reconfiguration Auctions.

III.13.4.5.1	Timing of Annual Reconfiguration Auctions.
III.13.4.5.2	Acceleration of Annual Reconfiguration Auction.
III.13.4.6	[Reserved.]
III.13.4.7	Monthly Reconfiguration Auctions.
III.13.4.8	Adjustment to Capacity Supply Obligations.
III.13.5	Bilateral Contracts in the Forward Capacity Market.
III.13.5.1	Capacity Supply Obligation Bilaterals.
III.13.5.1.1	Process for Approval of Capacity Supply Obligation Bilaterals.
III.13.5.1.1.1	Timing.
III.13.5.1.1.2	Application.
III.13.5.1.1.3	ISO Review.
III.13.5.1.1.4	Approval.
III.13.5.2	Capacity Load Obligations Bilaterals.
III.13.5.2.1	Process for Approval of Capacity Load Obligation Bilaterals.
III.13.5.2.1.1	Timing.
III.13.5.2.1.2	Application.
III.13.5.2.1.3	ISO Review.
III.13.5.2.1.4	Approval.
III.13.5.3	Supplemental Availability Bilaterals.
III.13.5.3.1	Designation of Supplemental Capacity Resources.
III.13.5.3.1.1	Eligibility.
III.13.5.3.1.2	Designation.
III.13.5.3.1.3	ISO Review.
III.13.5.3.1.4	Effect of Designation.
III.13.5.3.2	Submission of Supplemental Availability Bilaterals.
III.13.5.3.2.1	Timing.
III.13.5.3.2.2	Application.
III.13.5.3.2.3	ISO Review.
III.13.5.3.2.4	Effect of Supplemental Availability Bilateral.

III.13.6	Rights and Obligations.
III.13.6.1	Resources with Capacity Supply Obligations.
III.13.6.1.1	Generating Capacity Resources.
III.13.6.1.1.1	Energy Market Offer Requirements.
III.13.6.1.1.2	Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.
III.13.6.1.1.3	[Reserved.]
III.13.6.1.1.4	[Reserved.]
III.13.6.1.1.5	Additional Requirements for Generating Capacity Resources.
III.13.6.1.2	Import Capacity Resources.
III.13.6.1.2.1	Energy Market Offer Requirements.
III.13.6.1.2.2	Additional Requirements for Import Capacity Resources.
III.13.6.1.3	Intermittent Power Resources.
III.13.6.1.3.1	Energy Market Offer Requirements.
III.13.6.1.3.2	[Reserved.]
III.13.6.1.3.3	Additional Requirements for Intermittent Power Resources.
III.13.6.1.4	Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.
III.13.6.1.4.1	Energy Market Offer Requirements.
III.13.6.1.4.2	Additional Requirements for Settlement Only Resources.
III.13.6.1.5	Demand Resources.
III.13.6.1.5.1	Energy Market Offer Requirements.
III.13.6.1.5.2	Requirement that Offers Reflect Accurate Demand Response Capacity Resource Operating Characteristics.
III.13.6.1.5.3	Additional Requirements for Demand Resources.
III.13.6.1.5.4.	Demand Response Auditing.
III.13.6.1.5.4.1.	General Auditing Requirements for Demand Resources Excluding Demand Response Capacity Resources.
III.13.6.1.5.4.2.	General Auditing Requirements for Demand Response Capacity Resources.

III.13.6.1.5.4.3.	Seasonal DR Audits.
III.13.6.1.5.4.3.1.	Seasonal DR Audit Requirement.
III.13.6.1.5.4.3.2.	Failure to Request or Perform an Audit.
III.13.6.1.5.4.3.3.	Use of Event Performance Data to Satisfy Audit Requirements for Certain Resources.
III.13.6.1.5.4.3.3.1.	Demand Response Capacity Resources.
III.13.6.1.5.4.4.	Demand Resource Commercial Operation Audit.
III.13.6.1.5.4.5.	Additional Audits.
III.13.6.1.5.4.6.	Audit Methodologies.
III.13.6.1.5.4.7.	Requesting and Performing an Audit.
III.13.6.1.5.4.8.	New Demand Response Asset Audits.
III.13.6.1.5.4.8.1.	General Auditing Requirements for New Demand Response Assets.
III.13.6.1.5.5.	Reporting of Forecast Hourly Demand Reduction.
III.13.6.1.5.6.	Reporting of Monthly Maximum Forecast Hourly Demand Reduction.
III.13.6.2	Resources Without a Capacity Supply Obligation.
III.13.6.2.1	Generating Capacity Resources.
III.13.6.2.1.1	Energy Market Offer Requirements.
III.13.6.2.1.1.1	Day-Ahead Energy Market Participation.
III.13.6.2.1.1.2	Real-Time Energy Market Participation.
III.13.6.2.1.2	Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.
III.13.6.2.2	[Reserved.]
III.13.6.2.3	Intermittent Power Resources.
III.13.6.2.3.1	Energy Market Offer Requirements.

III.13.6.2.3.2	Additional Requirements for Intermittent Power Resources.
III.13.6.2.4	Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.
III.13.6.2.4.1	Energy Market Offer Requirements.
III.13.6.2.4.2	Additional Requirements for Settlement Only Resources.
III.13.6.2.5	Demand Resources.
III.13.6.2.5.1.	Energy Market Offer Requirements.
III.13.6.2.5.1.1.	Day-Ahead Energy Market Participation.
III.13.6.2.5.1.2.	Real-Time Energy Market Participation.
III.13.6.2.5.2.	Additional Requirements for Demand Response Capacity Resources Having No Capacity Supply Obligation.
III.13.6.3	Exporting Resources.
III.13.6.4	ISO Requests for Energy.
III.13.6.4.1	Real-Time High Operating Limit.
III.13.7	Performance, Payments and Charges in the FCM.
III.13.7.1	Performance Measures.
III.13.7.1.1	Generating Capacity Resources.
III.13.7.1.1.1	Definition of Shortage Events.
III.13.7.1.1.1.A	Shortage Event Availability Score.
III.13.7.1.1.2	Hourly Availability Scores.
III.13.7.1.1.3	Hourly Availability MW.
III.13.7.1.1.4	Availability Adjustments.
III.13.7.1.1.5	Poorly Performing Resources.
III.13.7.1.2	Import Capacity.
III.13.7.1.2.1	Availability Adjustments.
III.13.7.1.3	Intermittent Power Resources.
III.13.7.1.4	Settlement Only Resources.
III.13.7.1.4.1	Non-Intermittent Settlement Only Resources.
III.13.7.1.4.2	Intermittent Settlement Only Resources.

III.13.7.1.5	Demand Resources.
III.13.7.1.5.1	Capacity Values of Demand Resources.
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.
III.13.7.1.5.2	Capacity Values of Certain Distributed Generation.
III.13.7.1.5.3	Demand Reduction Values.
III.13.7.1.5.4	Calculation of Demand Reduction Values for On- Peak Demand Resources.
III.13.7.1.5.4.1	Summer Seasonal Demand Reduction Value.
III.13.7.1.5.4.2	Winter Seasonal Demand Reduction Value.
III.13.7.1.5.5	Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.
III.13.7.1.5.5.1	Summer Seasonal Demand Reduction Value.
III.13.7.1.5.5.2	Winter Seasonal Demand Reduction Value.
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.
III.13.7.1.5.7.1	Summer Seasonal Demand Reduction Value.
III.13.7.1.5.7.2	Winter Seasonal Demand Reduction Value.
III.13.7.1.5.7.3	Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources.
III.13.7.1.5.7.3.1	Determination of the Hourly Real-Time Demand Response Resource Deviation.
III.13.7.1.5.8	Demand Reduction Values for Real-Time Emergency Generation Resources.
III.13.7.1.5.8.1	Summer Seasonal Demand Reduction Value.

III.13.7.1.5.8.2	Winter Seasonal Demand Reduction Value.
III.13.7.1.5.8.3	Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Emergency Generation Resources.
III.13.7.1.5.8.3.1	Determination of the Hourly Real- Time Emergency Generation Resource Deviation.
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.
III.13.7.1.5.10.	Demand Response Capacity Resources.
III.13.7.1.5.10.1.	Hourly Available MW.
III.13.7.1.5.10.1.1.	Adjusted Audited Demand Reduction.
III.13.7.1.5.10.1.2.	Hourly Adjusted Audited Demand Reduction.
III.13.7.1.5.10.2.	Availability Adjustments.
III.13.7.1.6	Self-Supplied FCA Resources.
III.13.7.2	Payments and Charges to Resources.
III.13.7.2.1	Generating Capacity Resources.
III.13.7.2.1.1	Monthly Capacity Payments.
III.13.7.2.2	Import Capacity.
III.13.7.2.2.A	Export Capacity.
III.13.7.2.3	Intermittent Power Resources.
III.13.7.2.4	Settlement Only Resources.
III.13.7.2.4.1	Non-Intermittent Settlement Only Resources.
III.13.7.2.4.2	Intermittent Settlement Only Resources.
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.
III.13.7.2.5.2	Monthly Capacity Payments for Real-Time Emergency Generation Resources.

III.13.7.2.5.3.	Energy Settlement for Real-Time Demand Response Resources.
III.13.7.2.5.4.	Energy Settlement for Real-Time Emergency Generation Resources.
III.13.7.2.5.4.1.	Adjustment for Net Supply Generator Assets.
III.13.7.2.6	Self-Supplied FCA Resources.
III.13.7.2.7	Adjustments to Monthly Capacity Payments.
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.
III.13.7.2.7.1.1.1	Hourly PER Calculations.
III.13.7.2.7.1.1.2	Monthly PER Application.
III.13.7.2.7.1.2	Availability Penalties.
III.13.7.2.7.1.3	Availability Penalty Caps.
III.13.7.2.7.1.4	Availability Credits for Capacity Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources.
III.13.7.2.7.2	Import Capacity.
III.13.7.2.7.2.1	External Transaction Offer and Delivery Performance Adjustments.
III.13.7.2.7.2.2	Exceptions.
III.13.7.2.7.3	Intermittent Power Resources.
III.13.7.2.7.4	Settlement Only Resources.
III.13.7.2.7.4.1	Non-Intermittent Settlement Only Resources.
III.13.7.2.7.4.2	Intermittent Settlement Only Resources.
III.13.7.2.7.5	Demand Resources.
III.13.7.2.7.5.1	Calculation of Monthly Capacity Variances.
III.13.7.2.7.5.2	Negative Monthly Capacity Variances.
III.13.7.2.7.5.3	Positive Monthly Capacity Variances.
III.13.7.2.7.5.4	Determination of Net Demand Resource Performance Penalties and Demand Resource Performance Incentives .

III.13.7.2.7.6	Self-Supplied FCA Resources.
III.13.7.3	Charges to Market Participants with Capacity Load Obligations.
III.13.7.3.1	Calculations of Capacity Requirement and Capacity Load Obligation.
III.13.7.3.1.1	HQICC Used in the Calculation of Capacity Requirements.
III.13.7.3.1.2	Charges Associated with Self-Supplied FCA Resources.
III.13.7.3.1.3	Charges Associated with Dispatchable Asset Related Demands.
III.13.7.3.2	Excess Revenues.
III.13.7.3.3	Capacity Transfer Rights.
III.13.7.3.3.1	Definition and Payments to Holders of Capacity Transfer Rights.
III.13.7.3.3.2	Allocation of Capacity Transfer Rights.
III.13.7.3.3.3	Allocations of CTRs Resulting From Revised Capacity Zones.
III.13.7.3.3.4	Specifically Allocation of CTRs Associated with Transmission Upgrades.
III.13.7.3.3.5	[Reserved.]
III.13.7.3.3.6	Specifically Allocated CTRs for Pool Planned Units.
III.13.7.3.4	Forward Capacity Market Net Charge Amount.
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.
III.13.8.2	Filing of Forward Capacity Auction Results and Challenges Thereto.
III.13.8.3	[Reserved.]
III.13.8.4	[Reserved.]
III.14	[Reserved.]

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section III.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Resource, New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the financial assurance deposit described in Section III.13.1.9.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1.

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than \$200 per kilowatt of the whole resource's summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than \$100 per kilowatt of the whole resource's summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The \$100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.

The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output greater than 2 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, but less than or equal to the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than \$200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and in which investment in the resource was undertaken prior to

reactivation. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section does not cause the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement, the Project Sponsor must submit a New Capacity Qualification Package but is not required to submit a New Capacity Show of Interest Form for the incremental amount by the New Capacity Qualification Deadline. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.3 causes the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement or MW amount approved pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), the Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than \$200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.1.5. Treatment of Resources that are Partially New and Partially Existing.

For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.1.3 or Section III.13.1.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline. A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

III.13.1.1.1.7 Renewable Technology Resources.

To participate in the Forward Capacity Market as a Renewable Technology Resource, a Generating Capacity Resource must satisfy the following requirements:

- (a) receive an out-of-market revenue source supported by a state- or federally-regulated rate, charge or other regulated cost recovery mechanism;
- (b) qualify as a renewable or alternative energy generating resource under any New England state's mandated (either by statute or regulation) renewable or alternative energy portfolio standards as in effect on January 1, 2014, or, in states without a standard, qualify under that state's renewable energy goals as a renewable resource (either by statute or regulation) as in effect on January 1,

2014. The resource must qualify as a renewable or alternative energy generating resource in the state in which it is geographically located;

- (c) participate in a Forward Capacity Auction for a Capacity Commitment Period beginning on or after June 1, 2018 as a New Generating Capacity Resource pursuant to Section III.13.1.1, and;
- (d) has been designated for treatment as a Renewable Technology Resource pursuant to Section III.13.1.1.2.9.

An Export De-List Bid or Administrative Export De-List Bid may not be submitted for Generating Capacity Resources that assumed a Capacity Supply Obligation by participating in a Forward Capacity Auction as a Renewable Technology Resource.

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.

For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also submit to the ISO an Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the financial assurance deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. Upon submission of the financial assurance deposit by the Project Sponsor pursuant to Section III.13.1.9.1, the resource is obligated to participate and will be included in the Forward Capacity Auction at its FCA Qualified Capacity amount at the Forward

Capacity Auction Starting Price. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, material changes (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein. The New Capacity Show of Interest Form is available on the ISO website. A New Capacity Show of Interest Form to which a material change has been made shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor's contact information; the Project Sponsor's ISO customer status; the project's expected Commercial Operation date; the project address or location, and if relevant, asset identification number; the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project's equipment

configuration, including a description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall have the same meaning as set forth in Schedule 22 or Schedule 23, as applicable, of Section II of the Transmission, Markets and Services Tariff. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must submit, with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall mean that: (i) the Project Sponsor is the owner in fee simple of the real property on which the project will be located; (ii) the Project Sponsor holds a valid written leasehold interest in the real property on which the project will be located; (iii) the Project Sponsor holds a valid written option, exercisable solely by the Project Sponsor or its assignee, to purchase or lease property on which the project will be located; or (iv) the Project Sponsor holds a duly executed written contract to purchase or lease the real property on which the project will be located. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits.** In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated

with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing.** In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders.** In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2(d) and that accounts for more than five percent of the total project cost.

(d) **Substantial Site Construction.** In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery.** In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing.** In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (d) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent Commercial Operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning.** In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation.** In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. Offer Information.

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity at or above the Economic Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity Resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 the OATT.

III.13.1.1.2.2.4. Capacity Commitment Period Election.

In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional

and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity.

In addition to the information described elsewhere in this Section III.13.1.1.2.2:

- (a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.
- (b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.
- (c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource and Intermittent Settlement Only Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

- (a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);
- (b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource or the Intermittent Settlement Only Resource.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a material change (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service in a manner

that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource's Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s), as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

(g) New Generating Capacity Resources, or portions thereof, shall not be considered to have met their Capacity Supply Obligation for the purposes of this Forward Capacity Market and shall not receive compensation if any upgrades to be completed by the Project Sponsor required to remove overlapping interconnection impacts as identified in (f) have not been completed, including, any upgrades identified in a restudy pursuant to Section 3.2.1.3 of Schedule 22 and Section 1.7.1.3 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff and, if necessary, requests for the interconnection of an Elective Transmission Upgrade, in time for the Capacity Commitment Period unless the Capacity Supply Obligation is appropriately covered.

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource's New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

(a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;

- (b) whether the critical path schedule includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule are reasonable and likely to be met;
- (d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and
- (e) whether, in the case of an Intermittent Power Resource or Intermittent Settlement Only Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. [Reserved.]

III.13.1.1.2.7. Opportunity to Consult with Project Sponsor.

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

- (a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;
- (b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource's New Capacity Qualification Package was not accepted;
- (c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);
- (d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource's summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;
- (e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Generating Capacity Resource; (ii) for the notification to a Conditional Qualified New Generating Capacity Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Generating Capacity Resource, the Queue Position of the Conditional Qualified New Generating Capacity Resource; and
- (f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal Market Monitor's determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.1.2.9 Renewable Technology Resource Election.

A Project Sponsor or Market Participant electing Renewable Technology Resource treatment for the FCA Qualified Capacity of a New Generating Capacity Resource shall submit a Renewable Technology Resource election form no later than five Business Days after the date on which the ISO provides qualification determination notifications pursuant to Section III.13.1.1.2.8. Only the portion of the FCA Qualified Capacity of the resource that meets the requirements of Section III.13.1.1.1.7 is eligible for treatment as a Renewable Technology Resource.

Renewable Technology Resource elections may not be modified or withdrawn after the deadline for submission of the Renewable Technology Resource election form.

III.13.1.1.2.10 Determination of Renewable Technology Resource Qualified Capacity.

- (a) If the total FCA Qualified Capacity of Renewable Technology Resources exceeds the cap specified in subsections (b), (c) and (d) the qualified capacity value of each resource shall be prorated by the ratio of the cap divided by the total FCA Qualified Capacity. The ISO shall notify the Project Sponsor or Market Participant, as applicable, of the Qualified Capacity value of its resource no more than three Business Days after the deadline for submitting Renewable Technology Resource elections.
- (b) The cap for the Capacity Commitment Period beginning on June 1, 2018 is 200 MW.
- (c) The cap for the Capacity Commitment Period beginning on June 1, 2019 is 400 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior Capacity Commitment Period.
- (d) The cap for each Capacity Commitment Period beginning on or after June 1, 2020 is 600 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior two Capacity Commitment Periods.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Resource or Existing Demand Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only

Resource's net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006 summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be established pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e).

(b) The Intermittent Power Resource's or Intermittent Settlement Only Resource's summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.

(a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in each of the previous winter periods, or portion thereof if the

Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.

(b) The Intermittent Power Resource's and Intermittent Settlement Only Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2(a).

(c) The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the two treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) [Reserved.]

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, and if accepted by the ISO shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to

have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

The Dynamic De-List Bid Threshold beginning with the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018) shall be \$3.94/kW-month. The Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Dynamic De-List Bid Threshold shall be filed with the Commission under Section 205 of the Federal Power Act prior to the Existing Capacity Qualification Deadline for the associated Forward Capacity Auction.

III.13.1.2.3.1.1. Static De-List Bids.

An Existing Generating Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation at prices at or above the Dynamic De-List Bid Threshold during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section

III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests). Static De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.2. Permanent De-List Bids.

An Existing Generating Capacity Resource seeking to specify a price below which it would not accept a Capacity Supply Obligation permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource's full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource, an Intermittent Settlement Only Resource or a Renewable Technology Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource

submits de-list and export bids totaling the resource's full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource, an Intermittent Settlement Only Resource or a Renewable Technology Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity

Commitment Period. Administrative Export De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.

A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.

The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a resource that has a Permanent De-List Bid rejected by the Internal Market Monitor, a Non-Price Retirement Request may be submitted within 14 days after the resource receives notice of the rejection or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.

III.13.1.2.3.1.5.3. Reliability Review of Non-Price Retirement Requests.

The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

III.13.1.2.3.1.5.4. Obligation to Retire.

A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5.3(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the

obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.

III.13.1.2.3.1.6. Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. Internal Market Monitor Review.

The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

- (i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.
- (ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.
- (iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive de-listing of each individual asset in preferred de-list order.
- (iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of bids as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The bids of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will reject the bid as described in Section III.13.1.2.3.2.1.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

For purposes of this Section III.13.1.2.3.2, a Static De-List Bid, Permanent De-List Bid, or Export Bid shall be associated with a pivotal supplier if, using the best available estimates of FCA Qualified Capacity available at that time: (1) at the Forward Capacity Auction Starting Price, the total amount of FCA Qualified Capacity of all Existing Capacity Resources in the New England Control Area minus the Installed Capacity Requirement (net of HQICCs) is less than or equal to the greater of:

- (a) the amount of FCA Qualified Capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and
- (b) the amount of FCA Qualified Capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW;

or (2) where the bid is associated with a resource in an import-constrained Capacity Zone, if at the Forward Capacity Auction Starting Price, the total amount of FCA Qualified Capacity of all Existing Capacity Resources in the import-constrained Capacity Zone minus the Local Sourcing Requirement for the import-constrained Capacity Zone is less than or equal to the greater of:

- (a) the amount of FCA Qualified Capacity from all Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and
- (b) the amount of FCA Qualified Capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 100 MW.

In making this determination, the total amount of FCA Qualified Capacity of all Existing Capacity Resources will be reduced by an amount equal to the total of all pending Non-Price Retirement Requests and Permanent De-List Bids other than those submitted by the Lead Market Participant for the resource being evaluated, and the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource will include any capacity subject to a pending Non-Price Retirement Request or Permanent De-List Bid. The determination whether a Lead Market Participant is pivotal will be included in the qualification determination notification described in Section III.13.1.2.4. If the applicable Installed Capacity Requirement (net of HQICCs) and Local Sourcing Requirement are not finalized at the time that the Internal Market Monitor must make this determination, then the Internal Market Monitor shall use the best available estimates of those values available at that time, and shall publish those estimated values to the ISO website no later than the date that the qualification determination notifications are issued.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids Above the Dynamic De-List Bid Threshold, and Permanent De-List Bids Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid, each Export Bid above the Dynamic De-List Bid Threshold, and each Permanent De-List Bid above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the Existing Generating Capacity Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); (3) reasonable risk premium assumptions (as determined pursuant to Section III.13.1.2.3.2.1.4); and (4) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). Sufficient documentation and information about each of these bid components must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments and risk premiums, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate. The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

III.13.1.2.3.2.1.1.1. Review of Permanent De-List Bids and Export Bids.

(a) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(b) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(c) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.2.3, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1(c), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected 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 Lead Market Participant for such a resource may elect to have the ISO-determined bid entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b) by so indicating in a filing with the Commission in response to the informational filing described in Section III.13.8.1(a). Such a filing, and notification to the ISO of any such election, shall be made in accordance with the terms of Section III.13.8.1(b) and shall not limit the other rights provided under that section. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. In no case shall rejection of a de-list bid by the Internal Market Monitor restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.

- (a) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.
- (b) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

- (c) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.2(b), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected 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. In such a case, no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to submit revised prices for the Static De-List Bid for the resource at prices equal to or less than 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 and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. If no such election is made, and the Existing Generating Capacity Resource is entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c), then nothing in this subsection shall restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

III.13.1.2.3.2.1.2. Net Going Forward Costs.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net going forward costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. A Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing Generating Capacity Resource's net going forward costs based on a review of the data submitted in the following formula. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{[GFC - (IMR - PER)] \times InfIndex}{(CQ_{Summer, kw}) \times (12, months)}$$

Where:

GFC = annual going forward costs, in dollars. These are costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider

adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

$CQ_{\text{Summer}}kW$ = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid), this value shall be calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be \$0.00. As soon as practicable, the resource's total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected

InfIndex = inflation index. $\text{infIndex} = (1 + i)^4$

Where: "i" is the most recent reported 4-Year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.13.1.2.3.2.1.4. Risk Premium.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. This documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.13.1.2.3.2.1.2 may be included in this risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the Forward Capacity Market is consistent with the participant's corporate risk management practices.

III.13.1.2.3.2.1.5. Opportunity Costs.

To the extent that an Existing Generating Capacity Resource submitting a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, expected Capacity Performance Payments, or risk premium components of the bid, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading

index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. Administrative Export De-List Bids.

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

Age of Existing Resource (years)	Remaining Life (years)	Annual Rate of Capital Cost Recovery
1 to 5	30	0.106
6 to 10	25	0.110

11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource’s annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource’s annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{\text{Cost Of Capital}}{(1 - (1 + \text{CostOfCapital})^{-\text{RemainingLife}})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Qualification Determination Notification for Existing Capacity.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid including a determination whether the Lead Market Participant is pivotal as described in Section III.13.1.2.3.2 and indicating whether the bid has been accepted for participation in the Forward Capacity Auction. Where a Static De-List Bid, Permanent De-List Bid, Export Bid, or Administrative Export De-List Bid is not accepted for participation in the Forward Capacity Auction as a result of the Internal Market Monitor’s review pursuant to Section III.13.1.2.3.2, the notification shall include an explanation of the reasons the Existing Capacity Qualification Package was not accepted and shall include the resource’s net going forward costs and opportunity costs as determined by the Internal Market Monitor. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external Demand Resource may not be an Existing Import Capacity Resource or a

New Import Capacity Resource. External nodes shall be mapped to Capacity Zones as shown in the following table:

External Node Common Name	Capacity Zone
NB-NE External Node	Maine

HQ Phase I/II External Node	Rest-of-Pool
Highgate External Node	Rest-of-Pool
NY-NE AC External Node	Rest-of-Pool
Cross Sound Cable External Node	CT

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. Qualified Capacity for Existing Import Capacity Resources.

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3. Qualification Process for Existing Import Capacity Resources.

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

- (a) No later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting each Existing Import Capacity Resource must also submit to the ISO: (i)

documentation of a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, including documentation of the MW value of the contract; or (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Existing Import Capacity Resource during the Capacity Commitment Period, together with information to establish the summer and winter ratings of the resource(s) backing the import. In either case, the Market Participant must specify the interface over which the capacity will be imported.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply. An Existing Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, Existing Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

(c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3 for the duration of the contracts as listed. For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3, no later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3.

Contract Description	MW	Contract End Date
NYPA: NY – NE: CMEEC	13.2	8/31/2025
NYPA: NY – NE: MMWEC	53.3	8/31/2025
NYPA: NY – NE: Pascoag	2.3	8/31/2025
NYPA: NY– NE: VELCO	15.3	8/31/2025
	84.1	
VJO: Highgate – NE	Up to 225	10/31/2016
VJO: Highgate – NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II – NE	Up to 110	10/31/2016

III.13.1.3.4. Definition of New Import Capacity Resource.

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

For each New Import Capacity Resource, the Market Participant submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the entire Capacity Commitment Period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iv) documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the

energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load. For each New Import Capacity Resource, the Market Participant must specify the interface over which the capacity will be imported. The Market Participant must indicate whether the import is associated with any investment in transmission that increases New England's import capability. If the import will be backed by a single new External Resource, the Market Participant submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the Market Participant, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the New Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.

The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an

intervening Control Area or Control Areas shall comply with the following additional requirements: (1) For imports crossing a single intervening Control Area, the Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing. (2) For imports crossing more than one intervening Control Area, in addition to the requirements above, the Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load. (3) The Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.13.1.3.5.4. Capacity Commitment Period Election.

The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall not apply. A New Import Capacity Resource may not elect to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears.

III.13.1.3.5.5. Initial Interconnection Analysis.

The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources and Existing Import Capacity Resources.

In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from Existing Import Capacity Resources and New Import Capacity Resources. An offer from an Existing Import Capacity Resource or a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the

Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

III.13.1.3.5.8. Rationing Election.

The rationing election described in Section III.13.1.1.2.2.3(b) shall not apply. A New Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, New Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

III.13.1.4. Demand Resources.

III.13.1.4.1. Demand Resources.

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with an early Commercial Operation Date shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2017. No resource shall be permitted to participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life. Demand Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Resource. Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market Participant for a resource shall include the Enrolling Participant for a Demand Resource.

III.13.1.4.1.1. Existing Demand Resources.

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to (i) Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction, or (ii) Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program, as defined in Appendix E of this Market Rule 1, before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.

III.13.1.4.1.2. New Demand Resources.

A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.

For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources

For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.3. Special Provisions for Real-Time Emergency Generation Resources.

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a

Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.4.2. Show of Interest Form for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor's New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if

applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. Qualification Package for Existing Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. Qualification Package for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1. [Reserved.]

III.13.1.4.2.2.2. Source of Funding.

The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3. Measurement and Verification Plan.

For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4. Customer Acquisition Plan.

A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1. Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.

For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.2.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete

III.13.1.4.2.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor's ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor's program to deliver capacity to meet the Demand Resource Project Sponsor's Forward Capacity Auction obligations, and must include each customer's projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor's ability to fulfill its obligation by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource Project Sponsor shall be subject to the ISO's critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. Capacity Commitment Period Election.

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any

type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.2.5.

III.13.1.4.2.2.6. Rationing Election.

The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form. A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. Offers From New Demand Resources.

All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

III.13.1.4.2.5. Notification of Qualification for Demand Resources.

III.13.1.4.2.5.1. Evaluation of Demand Resource Qualification Materials.

The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

- (a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;
- (b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;
- (d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and
- (e) whether the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.

For each Existing Demand Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type; and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located, and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section

III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. Notification of Qualification for New Demand Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.

For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource's summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.

For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.3. Measurement and Verification Applicable to All Demand Resources.

To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply

Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. A Net Supply Generator Asset or other Generator Asset located at the same Retail Delivery Point as a Demand Response Asset that is associated with a Demand Response Capacity Resource may not participate in the Forward Capacity Market as a Generating Capacity Resource, provided that this exclusion shall not apply to a Generator Asset if it is separately metered and its output is added to the metered load as measured at the Retail Delivery Point. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects in reducing demand coincident with Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours such that the reported monthly Demand Reduction Value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the Demand Resource project's Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal

Peak Hours. The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor's total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor's total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Demand Resource Project Sponsors. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor's offer cleared. Additionally, the Updated Measurement and

Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors shall maintain records of retail customers served including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly Demand Reduction Values. For Demand Resource projects targeting customer facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor shall maintain records as described above for customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, or shall maintain records of aggregated Demand Reduction Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently delisted from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.

The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its

Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation, Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, 2017, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 2017, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity Commitment Periods commencing on or after June 1, 2017, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2017, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated based upon the Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the Retail Delivery Point, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated based upon the Average Hourly Load Reduction.

III.13.1.4.3.2.1. No Performance Data to Determine Demand Reduction Values.

Should a new Demand Resource, other than a Demand Response Capacity Resource, enter service at a time such that there is no performance data for June, July, August, December or January upon which to establish summer or winter seasonal Demand Reduction Values, and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, then the summer or winter seasonal Demand Reduction Values will be the simple average of its Demand Reduction Values for those months with a Capacity Supply Obligation. For a new Demand Resource, other than a Demand Response Capacity Resource, that enters service outside of the summer DR Auditing Period or winter DR Auditing Period and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, the Demand Resource Commercial Operation Audit results shall be used in the determination of the summer or winter seasonal Demand Reduction Value.

III.13.1.4.3.3. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.13.1.4.3.4. Measurement and Verification Costs.

Costs associated with measurement and verification of the Demand Resource project shall be borne by the Demand Resource Project Sponsor. Demand Resource Project Sponsors submitting application materials and Measurement and Verification Documents for review during the Forward Capacity Auction qualification process shall be subject to the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.4.4. Dispatch of Active Demand Resources During Event Hours.

III.13.1.4.4.1. Notification of Demand Resource Forecast Peak Hours.

The ISO shall issue notice to Market Participants concerning Demand Resource Forecast Peak Hours on the day before the relevant Operating Day. The notice issued pursuant to this section is for informational purposes only and shall not constitute a Dispatch Instruction.

III.13.1.4.4.2. Dispatch of Demand Resources During Real-Time Demand Resource Dispatch Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Demand Response Resources to curtail and restore loads during Real-Time Demand Resource Dispatch Hours. Dispatch Instructions shall apply to Real-Time Demand Response Resources. The amount of Demand Resources dispatched for each Real-Time Demand Resource Dispatch Hour will be the amount that the ISO determines is necessary to meet the reserve deficiency. The ISO may issue Dispatch Instructions that reduce or increase the amount dispatched in each hour.

III.13.1.4.4.3. Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Emergency Generation Resources to curtail and restore loads during Real-Time Emergency Generation Event Hours. Dispatch Instructions shall apply to specific Real-Time Emergency Generation Resources. The amount of Real-Time Emergency Generation Resources dispatched for each Real-Time Emergency Generation Event Hour will be the amount the ISO determines is necessary to meet the reserve deficiency.

III.13.1.4.5. Selection of Active Demand Resources For Dispatch.

III.13.1.4.5.1. Management of Real-Time Demand Response Assets and Real-Time Demand Response Resources.

A Market Participant must manage its Real-Time Demand Response Assets that are registered as a component of a Real-Time Demand Response Resource as of the first of a month so that the Real-Time Demand Response Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Demand Response Assets cause, or potentially cause, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to restore the loads of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Demand Response Asset or to restore the load of a dispatched Real-Time Demand Response Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the restoration of that asset. Market Participants with Real-Time Demand Response Assets shall report

to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Demand Response Resources consisting of an aggregation of more than one Real-Time Demand Response Asset shall report the load reduction and consumption, or generator output of the resource, to the ISO as the sum of the load reduction, consumption, or generator output of the individual assets making up that resource. Real-Time Demand Response Resources shall be assigned a unique resource identification number. The load reduction and consumption, or generator output of a Real-Time Demand Response Resource is reported to the ISO as a single set of values. A Real-Time Demand Response Resource shall consist of one or more Real-Time Demand Response Assets that are located within the same Dispatch Zone.

III.13.1.4.5.2. Management of Real-Time Emergency Generation Assets and Real-Time Emergency Generation Resources.

A Market Participant must manage its Real-Time Emergency Generation Assets that are registered as a component of a Real-Time Emergency Generation Resource as of the first of a month so that the Real-Time Emergency Generation Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Emergency Generation Assets causes, or potentially causes, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to discontinue the output of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Emergency Generation Asset or to discontinue the output of a dispatched Real-Time Emergency Generation Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the discontinued output of that asset. Market Participants with Real-Time Emergency Generation Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Emergency Generation Resources consisting of an aggregation of more than one Real-Time Emergency Generation Asset shall report the generator output of the resource to the ISO as the sum of the generator outputs of the individual assets making up that resource. Real-Time Emergency Generation Resources shall be assigned a unique resource identification number. The generator output of a Real-Time Emergency Generation Resource is reported to the ISO as a single set of values. A Real-Time Emergency Generation Resource shall consist of one or more Real-Time Emergency Generation Assets that are located within the same Dispatch Zone.

III.13.1.4.5.3. [Reserved.]

III.13.1.4.6. Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at Dispatch Zones.

III.13.1.4.6.1. Establishment of Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location and dispatch of Demand Response Capacity Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources. Dispatch Zones shall not change during a Capacity Commitment Period. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.13.1.4.6.2. Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

III.13.1.4.6.2.1. Real-Time Demand Response Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Demand Response Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Demand Response Resource into one or more Real-Time Demand Response Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.6.2.2. Real-Time Emergency Generation Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Emergency Generation Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Emergency Generation Resource into one or more Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.7. **[Reserved.]**

III.13.1.4.8. **[Reserved.]**

III.13.1.4.9. **Restrictions on Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Registration.**

A Market Participant may not register and, if previously registered, must retire in accordance with Section III.13.1.4.9.1, a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

III.13.1.4.9.1. Requirement for Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Retirement.

A Market Participant must retire a previously registered Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of customers specified in subsections (a) or (b) of Section III.13.1.4.9 no later than 12 months from the date that the ISO receives notice that the relevant electric retail regulatory authority prohibits such customer's demand response to be bid into the ISO-administered markets or programs or May 31, 2013, whichever is later.

III.13.1.4.10. Providing Information On Demand Response Capacity, Real-Time Demand Response and Real-Time Emergency Generation Resources.

If requested by a Market Participant with a registered Load Asset, the ISO will provide the following information about end-use customers served by the Market Participant: (a) whether the end-use customer's facility is registered with the ISO as part of an asset and whether the asset is associated with a Demand Response Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource, and; (b) the load reduction capability of the asset, as specified in the ISO's asset registration system, to which the end-use customer's facility is registered.

III.13.1.4.11. Assignment of Demand Assets to a Demand Resource.

The following mapping provisions apply to Demand Resources other than Demand Response Capacity Resources, the mapping for which is addressed in Appendix E to Market Rule 1.

(a) When a demand asset can be mapped to more than one Demand Resource, any demand assets shall be mapped to a commercial Demand Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period, before being mapped to a non-commercial Demand Resource or non-commercial increment of a Demand Resource.

(b) A demand asset cannot be unmapped from a Demand Resource if, following the unmapping, the sum of the audit values of the remaining demand assets that are mapped to the Demand Resource would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.2.4.5.3. Offers composed of separate resources may not be modified or withdrawn after the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Resource, April through November where the summer resource is a Demand Resource) of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period (October through May where the summer resource is not a Demand Resource, December through March where the summer resource is a Demand Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource or Intermittent Settlement Only Resource. If the winter capacity of the offer composed of separate resources in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone.

(e) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained.

(f) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone.

(g) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource.

(h) A Renewable Technology Resource may only participate in an offer composed of separate resources if its FCA Qualified Capacity has not been prorated pursuant to Section III.13.1.1.2.10.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than 5 Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource's final FCA

Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource's financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the financial assurance deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c) and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity's Capacity Load Obligation in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed

Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

(a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

- (b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.
- (c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.
- (d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.
- (e) If a Permanent De-List Bid above \$1.00/kW-month or a Static De-List Bid is approved by the Internal Market Monitor, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.
- (f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.13.1.9. Financial Assurance.

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy. The ISO and the NEPOOL Budget and Finance Subcommittee shall reconsider these financial assurance requirements no later than five years after the first Forward Capacity Auction is conducted.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Generating Capacity Resources) and New Demand Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial

Assurance Policy. Timely payment of the financial assurance deposit specified in the ISO New England Financial Assurance Policy by the Project Sponsor for a New Generating Capacity Resource or New Demand Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Resource in the Forward Capacity Auction at the starting price. If this financial assurance deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit shall be applied toward the resource's financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit will be returned pursuant to the terms of the ISO New England Financial Assurance Policy.

III.13.1.9.2. Financial Assurance for New Generating Capacity Resources and New Demand Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Resource's offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Resource: (i) fails to provide the required financial assurance on any required date for any reason; or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4(c), it shall lose its Capacity Supply Obligation (which shall then be entered by the ISO into subsequent annual reconfiguration auctions) and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. Release of Financial Assurance.

Once a New Generating Capacity Resource or New Demand Resource achieves Commercial Operation and is tested for its capacity rating, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand Resource is only

capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited. Any resulting shortfall in capacity shall then be entered by the ISO into subsequent annual reconfiguration auctions.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. Forfeit of Financial Assurance.

Where any financial assurance is forfeited pursuant to the provisions of this Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to the provisions of this Section III.13 shall be used to reduce payments incurred by load in the relevant Capacity Zone to replace that capacity.

III.13.1.9.2.4. Financial Assurance for New Import Capacity Resources.

A New Import Capacity Resource that is backed by a new External Resource shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource achieves Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. Qualification Process Cost Reimbursement Deposit.

For each New Capacity Show of Interest Form and New Demand Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below (“Qualification Process Cost Reimbursement Deposit”). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project’s critical path schedule monitored pursuant to Section III.13.3; and (ii)

the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22 or 23 of the OATT or where a resource modification does not require a revision to the Interconnection Agreement.

New Generating Resources ≥ 20 MW	New Generating Resources < 20 MW and ≥ 2 MW	Imports and New Demand Resources (including Distributed Generation)		New Generating Resources < 2 MW
<i>Including Up-rates, Re-powering, Environmental Compliance &</i>	<i>Including Up-rates, Re-powering, Environmental Compliance &</i>			

<i>Intermittent Power Resources</i>	<i>Intermittent Power Resources</i>			
\$25,000	\$7,500	\$1,000		\$500
<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>	<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>			
\$15,000	\$6500	n/a		n/a

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for Commercial Operation, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s) associated with the qualification process and critical path schedule monitoring, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO's consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
For all resources except Demand Resources, Nov. 1, 2006 through Jan. 2, 2007 For Demand Resources, Dec. 18, 2006 through Feb. 28, 2007	Apr. 30, 2007	June 15, 2007	Feb. 4, 2008	June 1, 2010
Sept. 18, 2007 through Nov. 14, 2007	Mar. 14, 2008	Apr. 29, 2008	Dec. 8, 2008	June 1, 2011
July 15, 2008 through Sep. 16, 2008	Feb. 3, 2009	Feb. 17, 2009	Oct. 5, 2009	June 1, 2012
May 15, 2009 through July 14, 2009	Dec. 1, 2009	Dec. 15, 2009	Aug. 2, 2010	June 1, 2013
Mar. 15, 2010 through May 14, 2010	Oct. 1, 2010	Oct. 15, 2010	June 6, 2011	June 1, 2014
Mar. 1, 2011 through Mar. 14, 2011	Aug. 1, 2011	Aug. 15, 2011	Apr. 2, 2012	June 1, 2015
Jan. 3, 2012 through Jan. 17, 2012	June 1, 2012	June 15, 2012	Feb. 4, 2013	June 1, 2016
Feb. 14, 2013 through Feb. 28, 2013	June 3, 2013	June 17, 2013	Feb. 3, 2014	June 1, 2017

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

- (a) each Capacity Commitment Period shall begin in June;
- (b) the New Capacity Show of Interest Submission Window will be in February (after the Forward Capacity Auction for the prior Capacity Commitment Period), approximately four years and three months before the beginning of the Capacity Commitment Period;
- (c) the Existing Capacity Qualification Deadline will be in June just over four years before the beginning of the Capacity Commitment Period;
- (d) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and
- (e) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

The table below shows this generic timeline for the Capacity Commitment Period beginning in year “X”, where X is any year after 2015.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
Feb. (X-4)	June (X-4)	June/July (X-4)	Feb. (X-3)	June X

III.13.2. 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 pursuant to Section III.13.2.3.3.

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

III.13.2.3. 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, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit an offer (a “New Capacity Offer”) indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource (in the associated modeled Capacity Zone during the qualification process) 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 associated modeled 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. Such 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, a New Import Capacity Resource, 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, \dots, p_m , where $P_S > p_1 > p_2 > \dots > p_m \geq P_E$, and let the associated quantities submitted for a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource be q_1, q_2, \dots, 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:

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

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) [Reserved.]

(v) A New Generating Capacity Resource (except a Renewable Technology Resource), New Import Capacity Resource, or New Demand 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.

(b) **Bids from Existing Capacity Resources Accepted in Qualification.** Static De-List Bids, Permanent De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources submitted and accepted in the qualification process (or as directed by the Commission) shall be automatically bid into the appropriate round(s) 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, 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. 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).

(c) **Existing Capacity Resources Not Having Accepted De-List or Export Bids and Self-Supplied FCA Resources.** Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource that did not submit a Static De-List Bid, a Permanent De-List Bid, an Export Bid, or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, or an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource that did not have any such bid accepted in the qualification process, 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 Generating Capacity Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity 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 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). An offer from at most one resource at a Conditional Qualified New Generating Capacity 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 Generating Capacity Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Generating Capacity 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 Generating Capacity 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 Generating Capacity 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 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 (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 (for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of the amount of capacity offered in the Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources) or the Capacity Zone’s Maximum Capacity Limit) plus (for each interface between the New England Control Area and an external Control Area, the lesser of that interface’s approved capacity transfer limit (net of tie benefits) or 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 Capacity Zone’s Local Sourcing Requirement; or

(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, 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 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, if 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 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 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 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) 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 the Capacity Zone's Maximum Capacity Limit; and

(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, 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) and the quantity of excess supply in the export-constrained Capacity Zone (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the Maximum Capacity Limit of the export-constrained Capacity Zone) and the quantity of capacity 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 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)) 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. The acceptance of a Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, or Permanent De-list Bid shall be 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. 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 Generating Capacity 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 Generating Capacity 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.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent 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.

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. Bids Rejected for Reliability Reasons.

The ISO shall review each Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid entered into the Forward Capacity Auction to determine whether the capacity associated with that Non-Price Retirement Request or de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction. 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. Non-Price Retirement Requests and 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 Non-Price Retirement Request or de-list bid may result in the procurement of less capacity than the Local Sourcing Requirement for Load Zones or aggregations of Load Zones considered for modeling in a Forward Capacity Auction. Where a Non-Price Retirement Request would otherwise be accepted, or a 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 Non-Price Retirement Request or 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 and the Non-Price Retirement Request will not be approved as described in Section III.13.1.2.3.1.5.3, and the following provisions will apply:

- (a) 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.

(i) In the case of Non-Price Retirement Request, the Lead Market Participant will be notified whether or not the request has been rejected for reliability reasons within 90 days of the submission of the request.

(b) A resource that has a de-list bid rejected pursuant to this Section III.13.2.5.2.5 shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1. An Existing Generating Capacity Resource or Existing Demand Resource that has a Non-Price Retirement Request rejected pursuant to this Section III.13.2.5.2.5 shall have the option to retire pursuant to Section III.2.5.2.5.3(a)(iii) or to continue operation and be compensated pursuant to Section III.13.2.5.2.5.1. A resource receiving payment under this Section III.13.2.5.2.5 and Section III.13.2.5.2.5.1 shall have Capacity Supply Obligations as described in Section III.13.6.1.

(c) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which prevented the de-listing of the resource 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).

(d) If the reliability need that prevented the de-listing of the resource is met through a reconfiguration auction or other means, the resource shall be de-listed, be relieved of its Capacity Supply Obligation and no longer be eligible to receive the compensation specified in Section III.13.2.5.2.5(b). The ISO shall enter bids at the Forward Capacity Auction Starting Price to replace the capacity on behalf of load in subsequent annual reconfiguration auctions associated with the Capacity Commitment Period (and subsequent Capacity Commitment Periods, in the case of a Permanent De-List Bid).

(e) If a Permanent De-List Bid that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request is rejected for reliability reasons, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Generating 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 until such time as it is no longer needed for reliability reasons.

(f) [Reserved.]

(g) The ISO shall review with the Reliability Committee (i) the status of any prior rejected delist bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Non-Price Retirement Request 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 an identified reliability need results in the rejection of a Non-Price Retirement Request, or the rejection of a 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. For de-list bids, this review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2. System needs associated with Non-Price Retirement Requests that are rejected for reliability reasons will be reviewed with the Reliability Committee prior to the notification of the Lead Market Participant that has submitted the Non-Price Retirement Request consistent with Section 13.2.5.2.5(a)(i).

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

(a)(i) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, or partial Permanent De-List Bid would otherwise clear in the Forward Capacity Auction but the de-list bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(a)(ii), 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.

(a)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(a)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the de-list bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(a)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the de-list bid was rejected.

(b)(i) In cases where a Permanent De-List Bid for the capacity of an entire resource would otherwise clear in the Forward Capacity Auction but the Permanent De-List Bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(b)(ii), 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 de-list bid as accepted for the Forward Capacity Auction 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 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 Permanent De-List Bid as accepted for the Forward Capacity Auction. 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 was submitted. Resources that elect payment based on the accepted Permanent De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent 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 was originally submitted.

(b)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(b)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Permanent De-List Bid

was rejected. Once qualified under this Section III.13.2.5.2.5.1(b)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the Permanent De-List Bid was rejected. 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 was rejected, payment pursuant to Section III.13.2.5.2.5.1(b)(i) will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(c)(i) In cases where a Non-Price Retirement Request for less than the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource will continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability. In cases where a Non-Price Retirement Request for the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource may elect to either (i) continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability, or (ii) the resource may elect to receive cost-of-service compensation 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 Non-Price Retirement Request rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid in the same manner as other listed capacity resources. 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 subject to refund while the rate is reviewed. In no event will compensation under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Non-Price Retirement Request was rejected.

(c)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(c)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request was rejected. Once qualified under this Section III.13.2.5.2.5.1(c)(ii), compensation will be provided for the 12-month Capacity Commitment Period for which the Non-Price Retirement Request was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Non-Price Retirement Request was rejected,

payment pursuant to Section III.13.2.5.2.5.1 will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(d) 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.

(e) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability.** If a Static De-List Bid or Permanent 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 Non-Price Retirement Request Resources:

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Non-Price Retirement Request for the entire resource rejected for reliability reasons pursuant to Section III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), 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(c), 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 of Resources

(a)(i) A resource, or portion thereof, that submits a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 will be retired coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted if the request is approved, or if not approved the resource nonetheless elects to retire pursuant to Section III.13.2.5.2.5.3(a)(iii). If the Non-Price Retirement Request is approved after the resource has a Capacity Supply Obligation for the Capacity Commitment Period for which the Non-Price Retirement Request was submitted, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation under Section III.13.2.5.2.5.1(c)(ii). 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) An Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-Price Retirement Request may retire the resource, or portion thereof, earlier than the Capacity

Commitment Period for which its Non-Price Retirement Request has been approved 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.

(a)(iii) In cases where an Existing Generating Capacity Resource or Existing Demand Resource has submitted a Non-Price Retirement Request and the request is not approved because the resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, the portion of the resource subject to the Non-Price Retirement Request may nonetheless retire as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted by notifying ISO within six months of receiving the notice from the ISO that the Non-Price Retirement Request has not been approved for reliability reasons. Such an election will be binding. A resource making an election pursuant to this Section III.13.2.5.2.5.3(a)(iii) will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or 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.

(b)(i) A resource that has submitted a non-partial Permanent De-List Bid that has cleared in the Forward Capacity Auction may retire the resource as of the Capacity Commitment Period for which its Permanent De-List Bid has cleared or earlier as described in Section III.13.2.5.2.5.3(b)(ii) 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.

(b)(ii) A resource with a cleared non-partial Permanent De-List Bid may retire the resource earlier than the Capacity Commitment Period for which its Permanent De-List Bid has cleared 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. A resource electing to retire pursuant to this provision must notify ISO in writing of its election to retire and the date of retirement. The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date on retirement.

(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 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) and shall be included in subsequent annual reconfiguration auctions (that is, the amount of capacity procured in subsequent annual reconfiguration auctions shall be increased by the amount of the de-listed or exported capacity).

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources and Existing Import Capacity Resources, 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 are subject to rationing, except 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.

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 a Capacity Zone at the precise amount of capacity 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 Generating Capacity 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 Generating Capacity Resource’s location or the offer associated with the Conditional Qualified New Generating Capacity 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 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 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), 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) In an import-constrained Capacity Zone having Inadequate Supply, the difference between the amount of capacity offered in the Capacity Zone through New Capacity Offers and the amount of New Capacity Required in that Capacity Zone shall be included in subsequent annual reconfiguration auctions.

(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), 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. 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 a rate equal to the lower of: (1) the Capacity Clearing Price; or (2) \$7.025/kW-month.

III.13.2.9. [Reserved.]

III.13.4. Reconfiguration Auctions.

For each Capacity Commitment Period that begins prior to June 1, 2018, 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 internal and external transmission limits and regional and local sourcing requirements updated using a methodology that is consistent with the Forward Capacity Auction) 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.

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 Non-Price Retirement Request 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 Qualification 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(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.13.1.1.2 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. 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 Qualification 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.13.4.2.1.2.1.2(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(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 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 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 determine whether the capacity associated with supply offers that would otherwise clear in a reconfiguration auction will result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the 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 determine whether the capacity associated with demand bids that would otherwise clear in a reconfiguration auction is needed to avoid a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction. 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) (including Local Sourcing Requirements and Maximum Capacity Limits for Capacity Zones for which price separation occurred in the Forward Capacity Auction for that Capacity Commitment Period) for the associated Capacity Commitment Period, to procure capacity not purchased in the Forward Capacity Auction as a result of Inadequate Supply, 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 interface transfer limits, as follows:

(a) 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 interface transfer 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. No later than 10 Business Days prior to the start of each annual reconfiguration auction, the ISO shall provide notice regarding whether the ISO will be submitting supply offers or demand bids in that auction.

(b) Any demand bid submitted by the ISO in an annual reconfiguration auction shall be at the Forward Capacity Auction Starting Price.

(c) 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.

(d) 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.

(e) 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.

(f) 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.13.6.2.1.1.

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.

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.

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.

**UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**ISO New England Inc. and
New England Power Pool**

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Docket No. ER14-____-000

**PREPARED TESTIMONY OF ROBERT G. ETHIER
ON BEHALF OF ISO NEW ENGLAND INC.**

1 **I. WITNESS IDENTIFICATION**

2 **Q: Please state your name, position and business address.**

3 A: My name is Robert G. Ethier. I am employed by ISO New England Inc. (the
4 “ISO”) as Vice President of Market Development. My business address is One
5 Sullivan Road, Holyoke, Massachusetts 01040.

6
7 **Q: Please describe your educational background and work experience.**

8 A: I have a Bachelor of Arts degree in Economics from Yale University, a Masters in
9 Resource Economics from Cornell University, and a Ph.D. in Resource
10 Economics from Cornell University. Since 2000, I have worked with the ISO in
11 various roles. I was responsible for Market Monitoring for nearly four years and
12 Resource Adequacy for more than two years before becoming Vice President of
13 Market Development in July 2008. Before 2000, I was a Senior Associate at
14 Stratus Consulting with responsibility for energy market modeling.

15

1 **II. OVERVIEW AND BACKGROUND**

2 **Q: What is the purpose of your testimony?**

3 A: The purpose of my testimony is to explain the design of the Forward Capacity
4 Market (“FCM”)¹ downward-sloping demand curve and the accompanying
5 changes (together, the “Demand Curve Changes”).

6

7 **Q: What are the components of the Demand Curve Changes?**

8 A: The Demand Curve Changes include: (1) Administrative estimates of the gross
9 cost of new entry (“CONE”) and Net CONE values that form the pricing
10 parameters of the demand curve; (2) a system-wide sloped demand curve, to be
11 implemented in time for the ninth Forward Capacity Auction (“FCA 9”); (3) the
12 permanent deletion of the system-wide Inadequate Supply and Insufficient
13 Competition rules; (4) the payment rates for zonal administrative pricing rules for
14 FCA 9; (5) an extension of the lock-in period for new resources; (6) an exemption
15 from the minimum offer rules for certain renewable resources, and; (7)
16 conforming changes needed to conduct FCA 9 with a system-wide sloped demand
17 curve.

18

19 **Q: How is your testimony organized?**

20 A: Following this introductory section, I have organized my testimony as follows:

21

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 (“ISO Tariff”) and the Participants Agreement.

1 In Section III, Cost of New Entry, I explain the significance of the
2 administratively determined Net CONE for demand curve design. I show why a
3 combined-cycle gas turbine with a Net CONE of \$11.08/kW-month is the
4 appropriate reference technology for New England. I also explain why the
5 consequence of setting Net CONE too low is far more severe than the
6 consequence of setting it too high.

7
8 In Section IV, Demand Curve, I describe the benefits and objectives of a
9 downward-sloping demand curve, including the central objective of meeting New
10 England's resource adequacy target. I explain the tradeoffs involved in designing
11 the New England demand curve and show how the ISO's demand curve
12 appropriately balances these tradeoffs. I explain that, for FCA 9, the demand
13 curve is applicable system-wide and not in the capacity zones.

14
15 In Section V, Administrative Pricing Rules, I discuss the deletion of the system-
16 wide Inadequate Supply and Insufficient Competition rules for FCA 9. I also
17 explain why the Net CONE value that underlies the system-wide demand curve is
18 the appropriate value for the remaining zonal administrative pricing rules.

19
20 In Section VI, Lock-In Period, I explain why an extension of the lock-in period,
21 from the current five years to seven years, is necessary in order to provide greater
22 certainty for new entry in New England given that merchant entry will be needed

1 as there are no vertically integrated utilities to construct new resources and given
2 the current lack of investor confidence in the FCM.

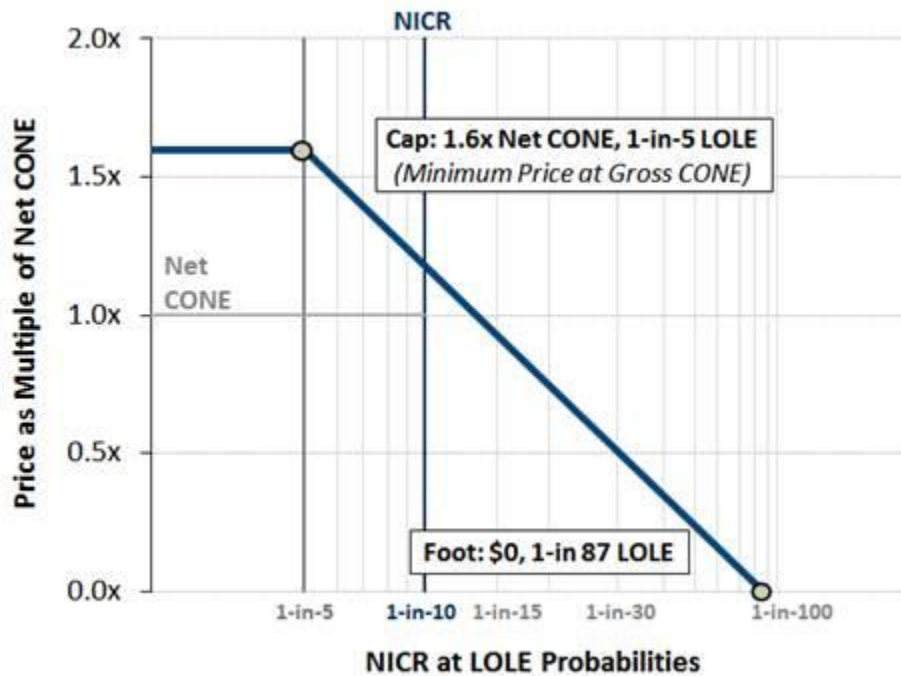
3
4 In Section VII, Renewable Technology Resources Exemption, I explain how the
5 Renewable Technology Resources exemption works, and why, under a sloped
6 demand curve, this exemption is appropriate for New England.

7
8 In Section VIII, Other Conforming Changes, I discuss several other conforming
9 changes needed to conduct FCA 9 with a system-wide sloped demand curve.

10

11 **Q: Please provide a general overview of the demand curve.**

12 **A:** The downward-sloping demand curve is depicted below.



13

14 The demand curve, like the capacity market itself, is designed to procure the
15 quantity of capacity required to meet the resource adequacy requirement for the

1 New England Control Area, the net installed capacity requirement (“NICR”), at
2 the true Net CONE. (In this testimony, I sometimes refer to the NICR as the
3 “installed capacity requirement.”) The Demand Curve Changes contain an
4 administrative Net CONE value of \$11.08/kW-month, estimated for a combined
5 cycle “reference unit.” This Net CONE value underlies the demand curve.
6 Because it is helpful to understand the Net CONE value and its role in demand
7 curve mechanics before delving into other aspects of the demand curve, I will first
8 address Net CONE and then go on to explain other features of the demand curve
9 and the Demand Curve Changes.

10

11 The ISO retained The Brattle Group (or “Brattle”) and Sargent & Lundy to
12 develop CONE and Net CONE values based on engineering and economic
13 estimates and to perform modeling to support the selection of a sloped demand
14 curve that meets New England’s reliability needs. These analyses are provided in
15 separate testimonies describing the development of Net CONE (the
16 “Newell/Ungate Testimony”) and the development of the demand curve (the
17 “Newell/Spees Testimony”).

18

19 **III. COST OF NEW ENTRY**

20 **Q: What is true Net CONE?**

21 A: The demand curve, like the FCM, is designed to ensure that prospective resource
22 developers are able to recover just enough money in the New England markets to
23 make it financially worth their while to build a power plant in New England when

1 the region is short of its resource target. In this testimony, I refer to the *true* cost
2 of competitive new entry into the FCM—the price actually required to entice a
3 resource to enter—as “true Net CONE.”

4

5 **Q: How does the administrative estimate of Net CONE differ from the true Net**
6 **CONE?**

7 A: The administrative Net CONE value is an estimate of the true Net CONE, and is
8 unlikely to be precisely equal to true Net CONE. Net CONE definitions can be
9 worded in various ways, but the term can be thought of as an estimate of the
10 minimum annual capacity payment that would be necessary for a new generating
11 facility, using a cost-effective reference technology type, to be economically
12 viable given reasonable expectations for the facility’s development and financing
13 costs, and reasonable expectations for the facility’s net revenue (taking into
14 account energy and ancillary services markets revenues) over its projected
15 lifetime. References to “Net CONE” in this testimony (as opposed to “true Net
16 CONE”) refer to the administrative estimate.

17

18 **Q: How does the Net CONE value relate to demand curve design?**

19 A: In order for the capacity market to pay resources their true Net CONE on average
20 over time while meeting the regional installed capacity requirement, the demand
21 curve must be designed to do the same. The estimate of Net CONE, along with
22 New England’s resource adequacy requirement, therefore forms the basis of the
23 demand curve. The Net CONE value sets the curve’s price parameters (y-axis

1 coordinates), including its height, and influences its slope. As the estimate of Net
2 CONE changes with the annual and periodic adjustments discussed below, the
3 curve adjusts upward or downward so that sufficient new entry will occur to meet
4 the installed capacity requirement. If instead the demand curve were fixed and
5 (for example) the true Net CONE were to rise, the expected long run price would
6 still be the true Net CONE, but the capacity market would not be expected to meet
7 the region's resource adequacy requirement, because at NICR the price
8 established under the demand curve would be less than true Net CONE.

9

10 **Q: Why isn't the demand curve designed using the MOPR values for Net CONE**
11 **recently approved by the Commission?**

12 A: As the Commission recognized, the minimum offer price rule ("MOPR") Net
13 CONE values, developed to determine the minimum offer price below which
14 market monitor review of an offer is required, are deliberately set at the low end
15 of the competitive range in order to subject resources to review only when it
16 appears that their offers could not be commercially plausible absent out-of-market
17 revenue. Because the Net CONE that underlies the demand curve is the price at
18 which the capacity market is designed to ensure that reliability standards are met,
19 it must be sufficient to allow merchant resources to enter the market and cannot
20 similarly be on the low end of estimates. Moreover, as I explain below, the
21 adverse consequences of underestimating Net CONE are far greater than those of
22 overestimating Net CONE. While the methodology used to develop the Net
23 CONE that underlies the demand curve is similar to the methodology used to

1 develop minimum offer prices, several changes have been made to remove the
2 low-end bias of the minimum offer prices.

3

4 **Q: What are the CONE and Net CONE values?**

5 A: The CONE value, the estimate of the gross cost of new entry of a combined cycle
6 unit, is \$14.04/kW-month. The Net CONE value is \$11.08/kW-month, which is
7 an estimate of what a combined cycle unit would need to recover from capacity
8 market revenue in its first year of operation to be willing to enter the market,
9 given the entrant's expectations about future capacity, energy, and ancillary
10 service revenues.

11

12 **Q: Will the administrative Net CONE value set the capacity clearing price?**

13 A: No. It is important to keep in mind that, while the Net CONE value is a crucial
14 component of the demand curve design, neither the Net CONE value nor the
15 demand curve set the long-term market clearing price. Assuming that the auction
16 is competitive, the demand curve largely determines the quantity purchased when
17 new entry is required and will have little impact on price. If new entry is not
18 required, the demand curve and supply curve together determine both quantity
19 and price, but this is not driven by the administratively determined Net CONE.
20 When new entry is needed, the price is determined by the payment needed to
21 make a new entrant willing to enter the market (the true Net CONE, rather than
22 the demand curve's Net CONE estimate). If there is a deep pool of competitive
23 entrants, whether the demand curve at true Net CONE is two percent short of

1 NICR or five percent long will have only a small effect on price because the
2 competitive entrants will create a relatively flat (elastic) supply curve where the
3 quantity available changes rapidly with changes in price.

4

5 **Q: What is the purpose of selecting a reference unit?**

6 A: When setting a demand curve, it is necessary to have an estimate of the expected
7 long-run price of capacity in order to calibrate the demand curve to actual market
8 costs. For example, if expected long-run entry prices are \$11.08/kW-month, the
9 demand curve should be designed to pay at least that value at the reliability target.
10 Without an estimate of this value, it is not possible to know whether the selected
11 curve would wildly overbuy or under-procure relative to the reliability target.

12

13 Estimating Net CONE is done most precisely from the perspective of a
14 hypothetical unit of a particular technology type in a particular location in New
15 England, which we refer to here as the “reference” unit. The choice of reference
16 unit has a large impact on the Net CONE value and is critical to ensuring that the
17 capacity market will procure capacity sufficient to meet the region’s resource
18 adequacy requirement.

19

20 **Q: Why is a combined cycle unit the appropriate reference technology for New**
21 **England?**

22 A: As discussed in the Newell/Ungate Testimony, The Brattle Group and Sargent &
23 Lundy examined a number of possible reference technologies and recommend the

1 two-by-one combined cycle plant (a combined cycle plant with two combustion
2 turbines and one steam turbine), with a Net CONE of \$11.08/kW-month. I agree
3 with The Brattle Group that a combined cycle unit is the appropriate reference
4 technology for New England. While the Frame combustion turbine unit is
5 substantially cheaper, it has never been built in New England and there are
6 substantial concerns that it may not be economically viable to do so because its
7 use with the required emissions control technology is still being proven. On the
8 other hand, the LMS100 (another combustion turbine unit) is a well established
9 technology, but, at a Net CONE of \$17.13/kW-month, it is considerably more
10 expensive than either the Frame combustion turbine or the combined cycle. The
11 combined cycle unit appropriately balances the competing considerations – it is
12 the most economic proven technology that was evaluated. Significantly, it is also
13 the only current generation technology that is actively being developed in the
14 region.

15
16 **Q: Why is the reference technology that is appropriate for New England not the**
17 **same as the reference technology in NYISO and PJM?**

18 A: Unlike the NYISO and PJM tariffs, which dictate that the reference technology
19 must be a combustion turbine, the ISO tariff allows the ISO to choose its
20 reference technology. The ISO retained The Brattle Group and Sargent & Lundy
21 to analyze the reference technology choice from the ground up. This analysis
22 represents the latest thinking on the choice of reference technology; among other
23 things, it has found that what was considered one of the primary advantages of

1 combustion turbines—minimum energy and ancillary services revenues error—
2 may not be true in New England. Given the Brattle and Sargent & Lundy
3 analysis, and given that the market has revealed that a combined cycle is the most
4 cost-effective technology that is likely to be built in New England (the only recent
5 merchant entrant in New England was a combined cycle unit), the ISO, supported
6 by NEPOOL and all six states, chose a combined cycle unit as the reference
7 technology. In contrast, the Frame unit with the required emissions control
8 technology is a still unproven technology that has not shown commercial
9 acceptance in New England and may not be economically viable because of risks
10 associated with the unproven technology.

11
12 Moreover, as I discuss more fully below, the dangers of understating Net CONE
13 are far greater than the dangers of overstating it, making the choice of the Frame
14 unit (with an estimated Net CONE of \$8.47/kW-month) much riskier than the
15 choice of a combined cycle unit (with an estimated Net CONE of \$11.08/kW-
16 month). If we choose the combined cycle unit as the reference technology and the
17 less expensive Frame unit turns out to be a viable technology (and so Net CONE
18 is set too high), the region will overbuy capacity by some amount, increasing
19 costs. But, for reasons I discuss below, these increased costs would be modest in
20 the context of the entire capacity market. On the other hand, if the lower priced
21 Frame unit is selected as the reference technology and the Frame unit turns out
22 *not* to be a viable technology in New England (and so Net CONE is set too low),
23 the region will procure insufficient capacity, which has a large reliability impact,

1 and the region will likely end up with a reliability problem that will be very
2 challenging to solve in a timely manner.

3

4 **Q: What are the dangers of setting Net CONE too high?**

5 A: As discussed above, prices will tend to converge around the true Net CONE, and
6 so the level of the administrative Net CONE will primarily affect the quantity of
7 capacity procured. The danger of getting the Net CONE value wrong is therefore
8 related to quantity. Specifically, the danger of setting the administrative Net
9 CONE above the true Net CONE is that the region will overbuy capacity over the
10 long term, resulting in modestly increased costs. Costs under the demand curve
11 are calculated by multiplying the market clearing price by the quantity of capacity
12 purchased. Costs of the capacity market in equilibrium therefore rise at the
13 constant rate of true Net CONE times the quantity of additional capacity.

14

15 Intuitively, if the administrative Net CONE is overstated, suppliers will enter and
16 set prices lower than the administrative Net CONE, and the quantity cleared in the
17 auction will exceed targets. Customers would not have to pay higher prices, but
18 they would procure surplus capacity that has diminishing value. For example, the
19 Newell/Ungate Testimony shows that a 33% overestimation error would lead to a
20 1.6 % higher reserve margin, costing customers about 1.6% more for capacity.
21 Customers would, however, benefit from lower energy prices and improved
22 reliability, somewhat offsetting the higher capacity costs.²

² See Brattle Group Report Prepared for the Federal Energy Regulatory Commission, *Resource Adequacy Requirements: Reliability and Economic Implications*, September 2013, available at

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Q: What are the dangers of setting Net CONE too low?

A: First, unlike costs, which rise linearly with the quantity of capacity, reliability is a highly non-linear function of capacity. As a consequence, the danger of setting the Net CONE value below the true Net CONE is that the under-procurement of capacity will have a large reliability effect. The Newell/Ungate Testimony shows that if Net CONE were underestimated by 33%, the market would clear about two percent less capacity on average, but shortages would be expected 50% more often.

A second danger of understating Net CONE is that if resources believe they cannot earn their true Net CONE in the capacity market, developers will add significant risk premiums to their offers, driving up the true Net CONE. There is evidence that the FCM may be facing risk premiums today; the demand curve design should solve, not exacerbate, this problem.

The Newell/Ungate Testimony indicates that the risk of under-procurement due to perceived regulatory risk and consequent risk premiums may be greater in ISO-NE than in other RTO markets due to New England’s lack of history of attracting merchant entry since implementing the FCM.

<https://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf> (“Resource Adequacy Report”) at pp. 103—106.

1 **Q: Why are the dangers of setting Net CONE too low much greater than setting**
2 **it too high?**

3 A: The fundamental reason for the asymmetry in the risks of over and
4 underestimating Net CONE is, as noted above, that reliability is a highly non-
5 linear function of capacity, while costs rise linearly with the quantity of capacity.
6 The non-linear nature of reliability can be seen by looking at the impact of
7 capacity deficits or surpluses on reliability: being 500 MW short may increase the
8 frequency of load shedding events by 46%, while being 500 MW long may only
9 decrease the probability by 29%. However, as noted above, costs for a market in
10 equilibrium rise (or fall) at a constant rate: true Net CONE x the quantity of
11 additional (or reduced) capacity. Because of this, reducing the amount purchased
12 may have a large reliability effect (e.g. a doubling of load shedding events) but
13 decrease costs by less than three percent (900 MW out of 34,000 MW).

14
15 **Q: How will CONE and Net CONE be updated?**

16 A: Not less than once every three years, CONE and Net CONE will be recalculated
17 using updated data. Whenever CONE and Net CONE are recalculated, the ISO
18 will review the results of the recalculation with stakeholders and the new values
19 will be filed with the Commission prior to the FCA in which the new value is to
20 apply. Between these recalculations, CONE and Net CONE will be adjusted for
21 each FCA pursuant to methods similar to those used to adjust Offer Review
22 Trigger Prices, Section III.A.21.1.2(e), except that energy and ancillary services

1 revenues will be adjusted using electricity futures data and not based on natural
2 gas prices.

3

4 **Q: Will different Net CONES apply to different capacity zones?**

5 A: No, not initially. As described in the Newell/Ungate Testimony, The Brattle
6 Group found that the calculated Net CONE in the Northeastern Massachusetts
7 (NEMA)/ Boston and Connecticut capacity zones would not be significantly
8 different from the system-wide value, so it did not propose separate Net CONE
9 values for the capacity zones. This finding will be revisited during the periodic
10 recalculations discussed above.

11

12 **IV. DEMAND CURVE**

13 **Q: What are the benefits of a downward-sloping demand curve?**

14 A: While the New England capacity market has achieved some of the high-level
15 goals that capacity markets are designed to accomplish, it has faced challenges in
16 several areas. Implementation of a sloped demand curve is the solution to some
17 of the key challenges facing the capacity market—properly setting the capacity
18 price when new entry is not needed and avoiding unnecessary price volatility. The
19 ISO has long recognized that replacing the capacity market’s “vertical demand
20 curve” with a downward-sloping demand curve would bring important
21 improvements to the FCM. These improvements include dampening price
22 volatility, reducing investment risk, reducing the costs to enter the market and
23 reducing the susceptibility of the market to the exercise of market power.

1 Because of these superior performance characteristics, the ISO has been on record
2 for over ten years as supporting downward-sloping demand curves in capacity
3 market design.

4

5 **Q: What are the objectives of a demand curve?**

6 A: The objectives of the demand curve are:

7 (1) Reliability: Maintain the one day in 10 years resource adequacy target on a
8 long-term average basis.

9 (2) Efficient Pricing: Short-run prices consistent with current fundamentals, going
10 above Net CONE during shortage and below Net CONE during surplus; with
11 prices consistent with the incremental value of capacity (that is, an additional
12 increment of capacity is worth less when capacity is in excess than when it is in
13 shorter supply).

14 (3) Mitigate Price Volatility: Reduce price volatility impact from lumpiness and
15 small movements and uncertainties in supply, demand, and transmission
16 (avoiding bimodal price distribution that leads to very high prices when capacity
17 is below NICR and very low prices when it is above NICR); produce few
18 outcomes at the administrative price cap.

19 (4) Reduce susceptibility to market power: Reducing demand when prices are
20 high is a fundamental market response to attempts to exercise market power.

21 (5) Minimize contentiousness and uncertainty from administrative parameters:

22 While the demand curve itself is administrative, it is a more transparent and direct

1 administrative structure than the Inadequate Supply and Insufficient Competition
2 rules, and one that is much less likely to require last-minute adjustments.

3

4 **Q: Why is the 1-in-10 resource adequacy standard an appropriate long-term**
5 **reliability target around which to design the demand curve?**

6 A: Most U.S. power system operators, including ISO-NE, determine planning
7 reserve margins to meet the one day in 10 years (or “1-in-10”) resource adequacy
8 criterion. This criterion establishes that the probability of disconnecting firm load
9 due to resource deficiencies (the loss of load expectation, or “LOLE”) shall be not
10 more than one day in 10 years (specified in the ISO tariff as the decimal
11 equivalent of 0.1 days per year). As Commission Staff observed in their August
12 2013 Report on Centralized Capacity Market Design Elements in Docket AD13-
13 7, a fundamental aspect of capacity markets is the targeted amount of capacity
14 needed to satisfy resource adequacy. ISO-NE, PJM and NYISO design their
15 capacity markets to target a 1-in-10 LOLE.³ ISO-NE’s demand curve, like the
16 demand curves of PJM and NYISO, is designed to meet the same standard.

17

18 **Q: Was the current vertical demand curve, with a cap at \$15.78/kW-month,**
19 **designed to meet the 1-in-10 standard?**

20 A: The current vertical curve was the result of a settlement process. There is no
21 public record of analysis that suggests that it would meet the one day in 10 years
22 standard on average, though the common assumption seems to have been that it
23 would as long as the cap value was at a reasonable level. However, as described

³ See Resource Adequacy Report at pp. 86—94.

1 in the Newell/Spees Testimony, when The Brattle Group evaluated the existing
2 vertical curve using its demand curve model, it did not meet a one day in 10 years
3 on average standard. That is, it was less reliable than the demand curve presented
4 here.

5
6 **Q: Please describe the tradeoffs involved in selecting a demand curve.**

7 A: Establishing a capacity market demand curve involves tradeoffs among reliability,
8 price volatility, and cost. Early on in the process the ISO established that any
9 proposed curve should meet the one day in 10 on average reliability standard.
10 This ensured that overall reliability would be equal across candidate curves, that
11 overall costs would be similar, and that proposed curves would not either attempt
12 to lower costs by sacrificing reliability or inflate costs by over-shooting the
13 reliability target. Other things constant, the flatter the curve, the greater the price
14 stability, but the more reserve margin uncertainty. This is because, with a flatter
15 demand curve, any movement of the supply curve to the right or the left will
16 result in a smaller change in price, but a greater change in quantity. A flatter
17 curve will also be more sensitive to inaccurate estimates of the true Net CONE.
18 On the other hand, the steeper the demand curve, the greater the price volatility,
19 but the lower the quantity volatility, and therefore, the smaller the likelihood of
20 low reliability outcomes and the less sensitive to inaccuracies in Net CONE
21 estimation. This is because, with a steeper demand curve, any given change in
22 supply will result in a greater change in price, but a smaller change in quantity.

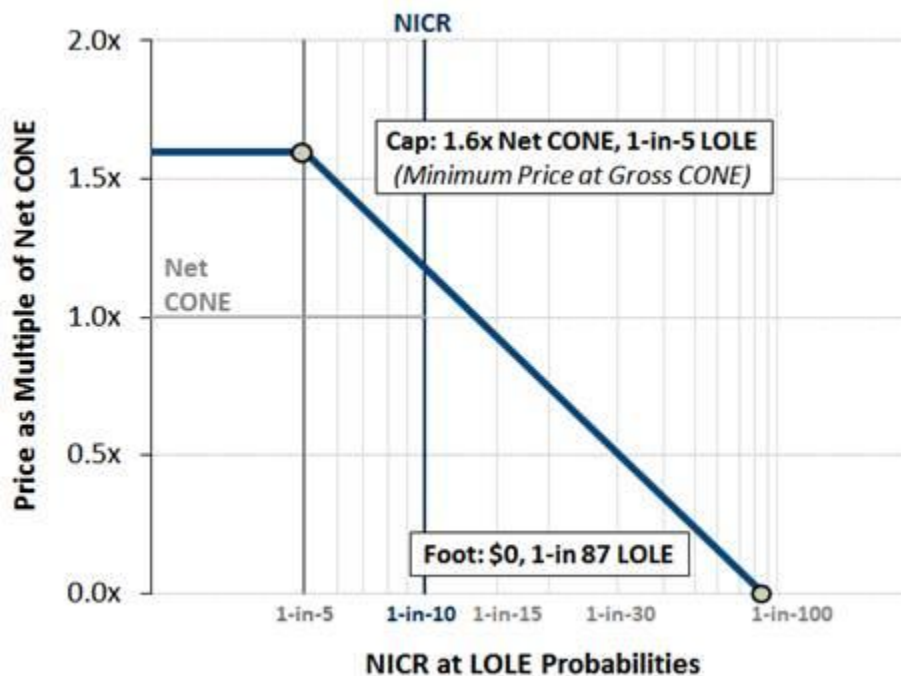
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1 The demand curves tested by Brattle, once they were tuned to meet the 1-in-10
2 standard, all had roughly the same costs.

3

4 **Q: Please describe the downward-sloping demand curve in general terms.**

5 A: The Demand Curve Changes include the sloped demand curve depicted below.
6 This curve achieves 1-in-10 LOLE on average when true Net CONE equals the
7 administrative Net CONE. The curve has a price cap at a price of 1.6 x Net
8 CONE that is reached when supply at the cap provides a 1-in-5 LOLE (one day in
9 five years, described in the tariff as the decimal equivalent, 0.200 LOLE) and a
10 “foot” (x-intercept) at a \$0.00/kW-month price at quantity that provides a 1-in-87
11 LOLE (one day in 87 years, described in the tariff as the decimal equivalent,
12 0.011).



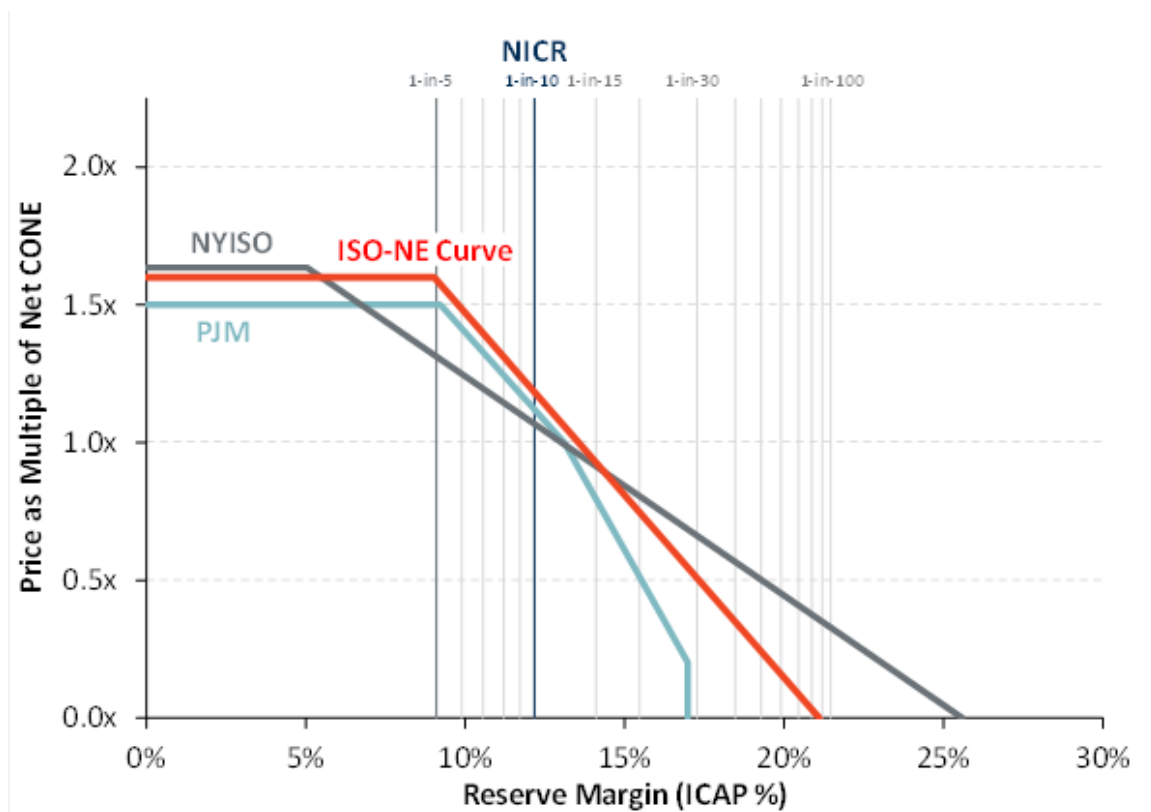
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14

1 **Q: How does the demand curve compare to the PJM and NYISO capacity**
2 **market demand curves?**

3 A: The ISO curve is comparable to the curves in the two other regions. As can be
4 seen below, the ISO curve is steeper than the NYISO curve and procures less at
5 low prices, while it is slightly flatter than the PJM curve and somewhat to the
6 right.

7



8

9

10 **Q: Please describe the stakeholder process leading up to the demand curve**
11 **design.**

12 A: The ISO and stakeholders engaged in an intense stakeholder process between the
13 time the Commission issued its order in January directing the ISO to implement a

1 demand curve and the NEPOOL Participants vote on March 21. There were six
2 meetings of the NEPOOL Markets Committee, including a meeting in January
3 before the order, as well as a meeting and vote of the NEPOOL Participants
4 Committee. The ISO and The Brattle Group made lengthy presentations at every
5 Markets Committee meeting.

6
7 The meetings were characterized by extensive back and forth discussions between
8 and among the presenters, state representatives, and stakeholders. These
9 presentations included details of the Net CONE calculation and extensive
10 discussions of The Brattle Group's demand curve model and candidate demand
11 curves. The ISO also posted a list of the numerous off-line questions and the
12 responses of the ISO and its consultants. The Brattle Group and Sargent & Lundy
13 incorporated many suggested changes in their final Net CONE calculations. The
14 Brattle Group provided results from their demand curve model for a large number
15 of state- and participant-submitted demand curves; in fact, the final proposed
16 demand curve is a version of a participant-submitted curve.

17

18 **Q: Please explain how the ISO arrived at the demand curve's key features.**

19 A: The ISO describes its demand curve in terms of loss of load criteria and
20 percentage of Net CONE because the capacity market is designed to procure, on
21 average, over the long term, a quantity that meets the loss of load criterion of one
22 day in 10 years, assuming that the ISO's estimates of the true Net CONE are
23 reasonably accurate. The curve is therefore defined in the tariff as a set of price

1 (y-coordinate) and quantity (x-coordinate) pairs, which are specified as a
2 percentage of Net CONE (y-coordinate) and LOLE (x-coordinate) pairs. The
3 slope between these points is the product of the placement of the points (that is,
4 the point placement determines the slope, not the other way around).

5
6 Price Cap: The demand curve has a price cap at 1.6 x Net CONE. The price cap
7 is reached when supply priced below the cap drops to 1-in-5 LOLE. The price
8 cap is subject to a minimum of 1 x (gross) CONE to prevent the curve from
9 collapsing and resulting in under-procurement if energy & ancillary services
10 revenues are projected to be very high. This cap level, in combination with the
11 rest of the Demand Curve Changes, strikes the right balance between limiting
12 market exposure to high prices when the market is not competitive and ensuring
13 that the cap is high enough to induce new entry, especially if the Net CONE
14 estimate is not accurate.

15
16 For reasons I discuss above, the greatest risk in designing a demand curve is to
17 produce a curve that does not provide resources the opportunity to recover their
18 true Net CONE. In a perfectly functioning market, the price cap (auction starting
19 price) should be set at a very high price, sufficient to ensure that a competitive
20 new entrant can always enter the market. A higher price cap (or no price cap at
21 all), would allow the market to always clear at a level sufficiently high to provide
22 an incentive for new entry even if it turns out that Net CONE is underestimated (if
23 it turns out, for example, that the combined cycle unit can no longer be built in

1 New England, and that the reference technology therefore should have been an
2 LMS100, with an estimated Net CONE of \$17.13/kW-month).

3
4 However, not all auctions are competitive. Under a demand curve, without
5 administrative pricing rules, in an uncompetitive FCA all resources receive an
6 auction clearing price limited only by the highest price on the demand curve. The
7 most recent auction, FCA 8, was not competitive, so this is a practical concern.
8 Stakeholders expressed the view, and the ISO agreed, that the price cap on the
9 demand curve must be selected keeping in mind the need to set reasonable
10 outcomes if the auction is not competitive.

11
12 Price at NICR: Another important point on the curve, though not one which is
13 used to define the curve, is the price at NICR. The proposed curve would pay
14 nearly 20% more than Net CONE at NICR. This is an important safeguard against
15 underestimating Net CONE – even if Net CONE were underestimated
16 substantially, there would still be a reasonable expectation that the FCA will
17 procure enough resources to meet NICR because the demand curve would be
18 capable of paying almost 20% more than the estimated Net CONE.

19
20 Foot: The demand curve sets a \$0.00/kW-month price at a quantity of 1-in-87
21 LOLE. This means that the demand curve sets a price that signals that quantities
22 above the foot have no value to the system. Given the selected price cap, this foot

1 placement (x-intercept) was required to ensure that the demand curve shape meets
2 the 1-in-10 LOLE standard.

3

4 **Q: Why is the ISO recommending this particular curve?**

5 A: There is a range of reasonable demand curves. The ISO has proposed this
6 particular demand curve because it appropriately balances the competing
7 objectives of a demand curve in the context of the New England markets: limiting
8 price volatility, limiting quantity (reliability) volatility, and limiting total
9 consumer costs.

10

11 When selecting its proposed curve and Net CONE, the ISO placed particular
12 attention on three issues. First, the price cap value: While economic theory,
13 under the assumption of a competitive market, would suggest a higher price cap
14 because the market price would not be expected to exceed the true Net CONE, in
15 practice, because it sets the price if an FCA is not competitive, the price cap of 1.6
16 x Net CONE is required to limit the risk of inappropriately high prices in an
17 uncompetitive FCA. Second, the intercept of the demand curve and NICR: The
18 demand curve crosses NICR at a value of $\approx 1.19 \times$ Net CONE, which helps
19 provide strong assurance of meeting the 1-in-10 target. Designing the curve to
20 pay materially above Net Cone at NICR is important because there will be price
21 and quantity volatility in the market, and because there will be error in the Net
22 CONE calculation; setting the intercept above Net CONE helps to address this.
23 Third, consequences of errors in Net CONE: As I discussed earlier, reliability

1 degrades quickly when the market is short, while the cost of buying more is
2 relatively modest and predictable.

3

4 **Q: How will the demand curve be updated?**

5 A: The demand curve price inputs, Net CONE and CONE, will be adjusted for each
6 FCA using methods similar to those used to adjust Offer Review Trigger Prices.

7 The demand curve quantity parameters will be adjusted annually using the
8 existing Installed Capacity Requirement process. The performance of the demand
9 curve will be evaluated regularly by the IMM and the external market monitor
10 and by the ISO; if necessary, the ISO will propose changes to remedy any
11 deficiencies.

12

13 **Q: Why is the ISO proposing a demand curve applicable only system-wide at
14 this time?**

15 A: The Demand Curve Changes implement a system-wide demand curve and
16 eliminate the accompanying system-wide administrative pricing rules. The sixty
17 days that the Commission provided for stakeholder discussions did not allow for
18 sufficient time to work through the mechanics of zonal demand curves, and
19 results of proposed zonal curves, with stakeholders. Moreover, the ISO could not
20 implement the zonal curves for FCA 9 given other current initiatives, such as
21 hourly offers. The ISO will continue to work with stakeholders and will submit
22 zonal demand curves in time for implementation for FCA 10.

23

1 **Q: What are the next steps in the demand curve project?**

2 A: The next stage of the demand curve project will include the following:

- 3 • Developing sloped demand curves for capacity zones (for FCA 10);
- 4 • Addressing administrative pricing rules for capacity zones (for FCA 10);
- 5 • Evaluating the continued use of descending clock auction structure after FCA
- 6 9, and;
- 7 • Conforming changes for new FCM rules, including the designs for conducting
- 8 reconfiguration auctions and bilateral transactions.

9

10 **Q: Why do the Demand Curve Changes sunset the existing reconfiguration**
11 **auction rules?**

12 A: The mechanics of reconfiguration auctions will change as a result of the
13 implementation of a system-wide demand curve, so the Demand Curve Changes
14 sunset the existing reconfiguration auction rules. The ISO is continuing to
15 develop updated reconfiguration auction rules and will submit the details of
16 reconfiguration auction mechanics in a forthcoming filing.

17

18 **V. ADMINISTRATIVE PRICING RULES**

19 **Q: Why is the ISO eliminating the system-wide Inadequate Supply and**
20 **Insufficient Competition rules?**

21 A: In its January 24 Order, the Commission directed ISO-NE to implement a sloped
22 demand curve in time for FCA 9 in large part because doing so would address the
23 challenging issues raised by setting the administrative price under the Inadequate

1 Supply and Insufficient Competition rules. In concert with a system-wide sloped
2 demand curve for FCA 9, the ISO is permanently eliminating the system-wide
3 Inadequate Supply and Insufficient Competition rules, beginning in FCA 9.

4

5 **Q: What are the purposes for the administrative pricing rules?**

6 A: The FCM includes three so-called administrative pricing rules: the Inadequate
7 Supply rule, the Insufficient Competition rule and the Capacity Carry Forward
8 Rule.

9

10 There are two fundamental purposes for the Inadequate Supply and Insufficient
11 Competition rules. The first purpose is to protect consumers from price spikes in
12 situations in which sellers could exercise market power and inappropriately raise
13 the market clearing price. The second purpose is to establish a just and
14 reasonable price for existing resources when these conditions occur.

15

16 The purpose of the Capacity Carry Forward Rule is to prevent price suppression
17 by excess new capacity that results from “lumpy” entry. Excess new capacity is
18 created when a new resource offer must be accepted to meet capacity
19 requirements, but that new resource is larger than necessary to meet the
20 requirements and the resource is not rationable. In such a circumstance, the FCA
21 in the relevant zone will overbuy new capacity, and the Capacity Carry Forward
22 Rule will be triggered in the following FCA. The Capacity Carry Forward Rule
23 applies only to import-constrained zones; because there was no lumpy new entry

1 in an import-constrained zone in FCA 8, the Capacity Carry Forward Rule will
2 not trigger in FCA 9.

3

4 **Q: What is the payment rate for the administrative pricing rules for FCA 9?**

5 A: The Demand Curve Changes update the zonal administrative pricing rates for the
6 Inadequate Supply, Insufficient Competition, and Capacity Carry Forward Rules
7 so that they reflect the \$11.08/kW-month Net CONE value that underlies the
8 system-wide sloped demand curve. There are no longer system-wide
9 administrative pricing rules, so the rule changes contain no system-wide
10 administrative pricing provisions.

11

12 Specifically, the rule changes provide that if the Inadequate Supply or Insufficient
13 Competition rules trigger, existing resources will receive the \$11.08/kW-month
14 Net CONE value or, if it is higher, the capacity clearing price for the rest-of-pool
15 capacity zone. (The latter because with a system-wide demand curve in place, it
16 is possible that the system-wide price will be higher than the zonal price, and in
17 that event, the higher price more accurately reflects the value of the capacity that
18 the resource provides to the system. That is, capacity in an import-constrained
19 zone is at least as valuable as rest-of-pool capacity, and that should be reflected in
20 any administrative pricing.) The new payment rate for the Capacity Carry
21 Forward Rule is also \$11.08/kW-month. However, this provision cannot be
22 triggered in FCA 9 because there was no lumpy new entry in an import-
23 constrained zone in the last FCA.

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Q: Why is it appropriate to set the zonal administrative pricing rates to reflect Net CONE?

A: As discussed earlier, the demand curve changes include a system-wide sloped demand curve for FCA 9, and the ISO will propose sloped demand curves for the capacity zones in a forthcoming filing. Therefore, the capacity zones will retain vertical demand curves for FCA 9, and with them, the need for administrative pricing in import-constrained zones. (Administrative pricing applies only in import, and not export, constrained zones.)

Net CONE is the appropriate rate under administrative pricing because it is the best estimate of the price that would result from a competitive auction.

Conceptually, it stands to reason that administrative pricing rules should aim for the same target as the demand curve and the capacity market design as a whole: that is, they should aim to pay prices just high enough to attract sufficient new investment to meet resource adequacy objectives. We now have the benefit of Brattle Group and Sargent & Lundy calculations estimating that, in New England, the value of that target price is \$11.08/kW-month.

The Demand Curve Changes do not alter the triggering conditions of any of the zonal administrative pricing rules.

1

2 **VI. LOCK-IN PERIOD**

3 **Q: What is the current lock-in period in the FCM?**

4 A: Under the existing FCM rules, a new resource offering into an FCA can elect to
5 receive, should its offer clear, the capacity clearing price associated with that
6 year's FCA for up to four additional capacity commitment periods (for a total of a
7 five-year "lock-in"). Whether the capacity clearing prices for those four
8 subsequent FCAs are above or below the resource's locked-in price, the resource
9 will receive its first-year FCA price, indexed for inflation.

10

11 **Q: What change is proposed for the lock-in period?**

12 A: As part of the package of rule changes proposed by the ISO and supported by
13 NEPOOL and the six states, the allowable lock-in period is increased from the
14 current five years to seven years (the FCA in which the new resource clears and
15 six additional capacity commitment periods).

16

17 **Q: What is the purpose of providing new entrants a lock-in period?**

18 A: The FCM and other capacity market designs include lock-in periods because
19 developers have a preference for price certainty: they will offer into the capacity
20 market at a lower price if they are guaranteed that price for a number of years.

21

22 **Q: Why is a seven year lock-in period appropriate now in New England?**

1 A: The Commission and others have expressed concern that lock-in periods result in
2 short-term price discrimination. We acknowledge this concern, but the perceived
3 risks in the FCM are currently unnaturally high and reflect more than the normal
4 volatility that the initial five-year lock-in period was designed to ameliorate.
5 Furthermore, unlike other RTO markets, New England does not have vertically
6 integrated utilities that can step in and build new resources to meet load if
7 merchant entry does not occur. When the New England states restructured their
8 utilities, they effectively removed the obligation to serve from a generation
9 perspective and barred utility ownership of generating resources. Therefore, the
10 merchant market is the only sector that can provide new generation in New
11 England.

12
13 **Q: Why does the ISO say that there is a lack of confidence in the FCM, and**
14 **what does that lack of confidence do to the market?**

15 A: During ISO's discussions with potential project developers, equity backers, and
16 others involved in the development and finance of new resources, they
17 consistently expressed the concern that New England has a long history of low
18 and administratively determined capacity prices and state-sponsored generation
19 entry that was perceived, at least in part, as designed to reduce capacity prices.
20 As noted in the Newell/Ungate Testimony, many investors say they perceive the
21 New England market as being riskier than other markets.

22

1 This has resulted in a lack of confidence in the New England market because of
2 the regulatory risk that the market will not be allowed to consistently produce
3 prices that reflect the true Net CONE when needed. As a result, some developers
4 have consistently said that they dramatically discount capacity market revenues
5 beyond the current five year lock-in, and that they will continue to do so until
6 there is a sufficient history of competitive market outcomes.

7
8 **Q: Please explain how the demand curve price cap is related to the discussion of**
9 **the lock-in period and regulatory risk.**

10 A: The ISO considered addressing this perceived regulatory risk by setting a
11 relatively high price cap as part of the demand curve and allowing new entrants to
12 reflect the perceived regulatory risk in their offers. One of the first curves the ISO
13 considered as part of the stakeholder process had a cap set at 2 x Net CONE, or
14 over \$23.00/kW-month. This combined with the current five year lock-in would
15 still allow new entry even with severe discounting of future capacity market
16 revenues. However, lowering the cap increases the probability that new entrants
17 will choose not to enter the market if they see significant regulatory risk beyond
18 the price lock-in period. Extending the lock-in compensates for a lower price cap.

19
20 **Q: Why is extending the lock-in period preferable to increasing the price under**
21 **current market conditions?**

22 A: Increasing the price cap to \$23.00/kW-month would leave consumers exposed to
23 very high prices in the event that an auction is not competitive, as was

1 experienced in the most recent FCA. Moreover, it is not clear that it is desirable
2 to allow the market price to reflect such a high degree of regulatory risk. These
3 are perceived regulatory risks that are driven by the relative newness of the
4 market design and the history of excess capacity maintained by continued
5 regulatory intervention in New England via six annual auctions with price floors,
6 price floors that were motivated, in part, by the need to correct for substantial
7 subsidized out-of-market entry. As such, these are near-term risks, not long-run
8 features of the market. And while they could be addressed by setting a high price
9 cap, it is consumers who will bear the full brunt of the resulting high capacity
10 market clearing price. It is instead preferable to have consumers reduce these
11 near-term risks by providing a longer lock-in, which will send a price signal that
12 is more consistent with long run expectations of a stable and robust market
13 design. The ISO proposes to do that through extending the price lock-in to seven
14 years. The figure below illustrates how an extension of the lock-in helps to
15 address the perceived regulatory risk.

16

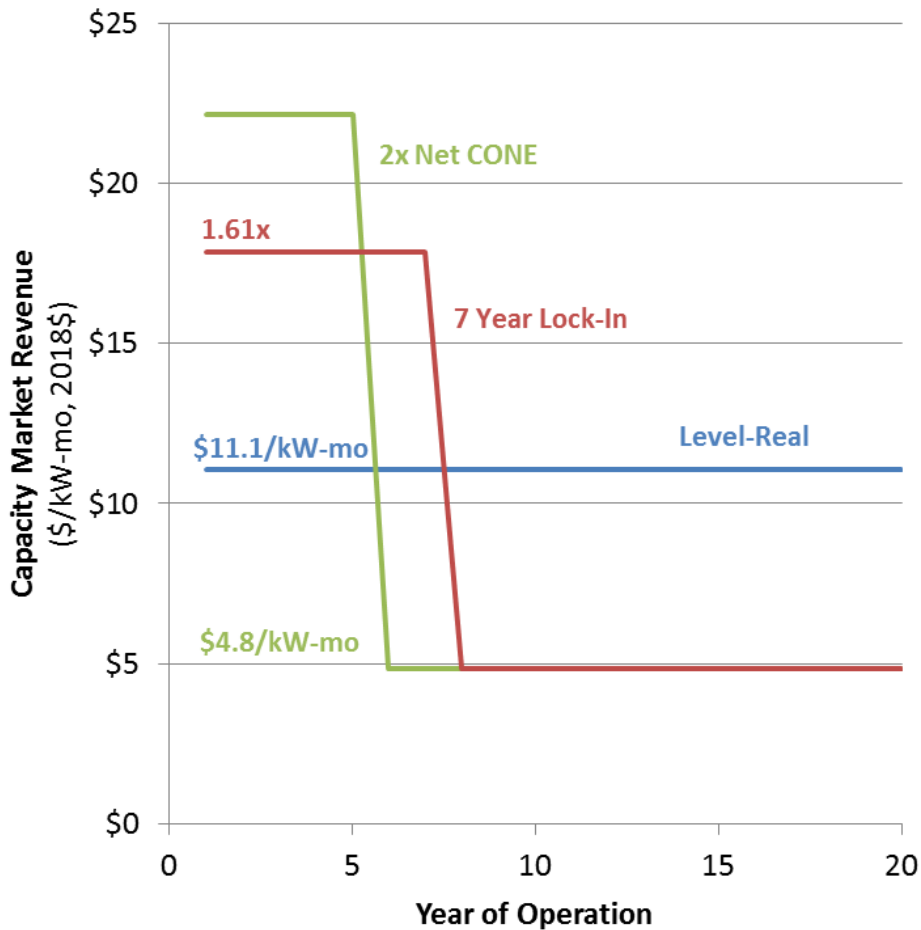
17 **Q: Please explain the specific trade-off between the price cap included in the**
18 **Demand Curve Changes and the lock-in period included in the Demand**
19 **Curve Changes.**

20 A: The Brattle Group, on behalf of the ISO, developed this example to support
21 stakeholder discussions when the ISO revised its demand curve to lower the price
22 cap from 2 x Net CONE. This example shows that the ISO's proposed 1.6 x Net
23 CONE cap, when coupled with a seven year lock-in, will enable entry as well as a

1 2 x Net CONE cap and a five year lock-in when potential entrants heavily
2 discount capacity market revenues beyond the period of the lock-in.

3

4 The figure below shows two different expected revenue streams that each result in
5 the same level-real value equal to the ISO's proposed Net CONE. The green line
6 below, labeled 2 x Net CONE, shows that a new entrant making an offer at a price
7 cap of 2 x Net CONE with a five year price lock-in could discount post lock-in
8 capacity values by over 50% and still expect sufficient revenues to meet the need
9 to earn Net CONE over the project's 20 year life. This discounting of over 50%
10 is consistent with the discounting levels expressed by several parties in
11 discussions about new entry in New England. The red line, labeled 7 Year Lock -
12 In, shows the required offer to achieve the same level-real value as the first offer
13 at 2 x Net CONE, under a design with a seven year lock-in and the same 50+%
14 discounting of post-lock-in revenues. The required offer drops from 2 x Net
15 CONE to 1.61 x Net CONE. This figure shows how increasing the lock-in
16 compensates for a lower price cap.



1

2 **Q: Why is it appropriate to extend the lock-in period?**

3 A: It is appropriate to extend the lock-in to ensure that needed new entry occurs with
 4 the 1.6 x Net CONE cap and the resulting demand curve. As the ISO and The
 5 Brattle Group have described, investors are skeptical of the New England market;
 6 the 1.6 x Net CONE cap value by itself may not be sufficient to induce
 7 investment. Moreover, the cap value is paid only to reach the 1-in-5 reliability
 8 level, yet the ISO is seeking to achieve a 1-in-10 reliability level. The demand
 9 curve pays well under the price cap at the NICR quantity. The lock-in extension
 10 will help make entry possible, and make the upcoming auctions successful, in the
 11 presence of perceived regulatory risk by project developers. It is expected that

1 recent resource retirements, introduction of a sloped demand curve, and
2 elimination of system-wide administrative pricing will help to establish a robust
3 and stable capacity market, which will render the currently-required regulatory
4 risk premiums unnecessary. This will in turn reduce the need for a seven year
5 lock-in in the future. Put another way, if the Commission believes that the instant
6 reforms will result in a good long-term design, taking short-term steps to address
7 the regulatory risk premium will prevent a needless wealth transfer from
8 consumers to producers until the market is sufficiently established that such a
9 regulatory premium is not necessary, and will also enable the market design to
10 protect against extreme prices in the event that a future auction is not competitive.
11 And there is little rationale for sending a price signal reflecting a short-term risk
12 created by the regulatory process itself when there are alternative approaches
13 available.

14
15 Restoring confidence in the market is likely to require multiple auctions with
16 competitive new entry. Modestly extending the period during which new
17 resources can elect to receive their initial capacity clearing price will help reduce
18 this risk. The ISO will reevaluate the lock-in period after a series of successful
19 auctions.

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1 **VII. RENEWABLE TECHNOLOGY RESOURCES EXEMPTION**

2 **Q: Please explain the Renewable Technology Resources exemption.**

3 A: The Demand Curve Changes allow a limited amount of new generating resources
4 to be classified as Renewable Technology Resources and exempted from the
5 Offer Review Trigger Prices. The rule changes place a 200 MW limit on the
6 amount of resources that can be designated Renewable Technology Resources in
7 each FCA and allows for carry-forward of unused amounts of the annual limit
8 from the prior two years.

9

10 **Q: How does a resource qualify as a Renewable Technology Resource?**

11 A: To qualify as a Renewable Technology Resource, a resource must: (1) receive an
12 out-of-market revenue source supported by a state- or federally-regulated rate,
13 charge or other regulated cost recovery mechanism, and; (2) qualify as a
14 renewable or alternative energy generating resource under any New England
15 state's mandated renewable or alternative energy portfolio standards or, in states
16 without a standard, qualify under that state's renewable energy goals as a
17 renewable resource. The resource must qualify as a renewable or alternative
18 energy generating resource in the state in which it is geographically located.

19

20 **Q: Please provide an example of how the unused portion of the annual limit is**
21 **carried forward.**

22 A: If no resources are classified as Renewable Technology Resources in FCA 9, the
23 200 MW limit will be carried-forward and the limit in the second year (FCA 10)

1 will be raised to 400 MW. If once again no resources are classified as Renewable
2 Technology Resources, the limit in the third year (FCA 11) will be raised to 600
3 MW. But if in the fourth year (FCA 12) again no resources qualify as Renewable
4 Technology Resources, the limit will stay at 600 MW (and will not exceed 600
5 MW going forward). If in any FCA the total limit is met, the following FCA will
6 return to a 200 MW limit.

7

8 **Q: Why is the Renewable Technology Resources exemption appropriate for New**
9 **England?**

10 A: In response to the Commission's suggestion that the ISO work with its
11 stakeholders to design a renewable resources exemption, the ISO, supported by
12 the majority of its stakeholders, has developed the Renewable Technology
13 Resources exemption. Designing the capacity market to accommodate the public
14 policy objectives of the six New England states while limiting the resulting price
15 impacts is a challenging task. In discussions with stakeholders in 2012 and before
16 the Commission last year, the ISO indicated that exempting renewable resources
17 from offer-floor mitigation should only be considered if paired with the inclusion
18 of a sloped demand curve in the capacity market. The Commission likewise has
19 recognized that the inclusion of a demand curve in capacity market design
20 simplifies the task of balancing state interests and market efficiency.

21

22 It is true, as the ISO has argued in the past, that if the states choose to build
23 uneconomic resources outside of FCM to further their public policy goals it is

1 they, not the FCM, who are responsible for redundant capacity. However, it is
2 equally true that if resources are to be built pursuant to state-sponsored initiatives,
3 it would be economically inefficient not to include them as counting toward
4 meeting regional capacity requirements, because excluding them would require
5 the building of a second, redundant set of resources to meet the same need. The
6 Renewable Technology Resources exemption acknowledges that these state-
7 sponsored resources do or will exist and reasonably addresses the inherent
8 conflict between certain legitimate state actions and setting appropriate prices in
9 the FCM.

10

11 **Q: How would a renewable resources exemption have affected prices under a**
12 **vertical demand curve?**

13 A: Exempting resources from the minimum offer price rules applied to new entrants
14 allows them to offer into the FCM as price takers, which has the same effect on
15 the capacity clearing price as a zero price offer. Using a vertical demand curve,
16 the FCM relied entirely on the submitted offers of resources to set prices, so
17 displacing new merchant entry with a zero-priced renewable resource when new
18 entry was needed, and counting on a (likely much lower-priced) delist bid to set
19 the market clearing price would have a large downward effect on prices. In fact,
20 if all resources offered as price takers at a quantity equal to NICR under a vertical
21 demand curve, the price would be set at zero.

22

1 **Q: How will a renewable resources exemption affect prices under a sloped**
2 **demand curve?**

3 A: Under the ISO sloped demand curve, the same scenario—all resources offering as
4 price takers at a quantity equal to NICR (which implies that there is no new
5 merchant entry)—results not in a zero price, but in a price of approximately
6 \$13.00/kW-month—the price at which the demand curve crosses NICR. This is a
7 substantial improvement in pricing that will significantly reduce the expected
8 impacts of subsidized renewables entering the market. And while not all
9 circumstances will result in such significant price differences between sloped and
10 vertical demand curves, the example does indicate why the sloped demand curve
11 is a necessary market feature for the ISO to support the Renewable Technology
12 Resources exemption.

13
14 **Q: Why is it appropriate to limit the quantity of resources that can qualify as**
15 **Renewable Technology Resources?**

16 A: Placing a limit on the amount of resources that can be designated Renewable
17 Technology Resources will ensure that the exemption contains a backstop to
18 prevent systematic downward pressure on prices. While PJM does not limit the
19 amount of solar and wind resources that are exempted annually from its minimum
20 offer price rules, the smaller size of the New England market relative to the likely
21 amount of renewable entry makes limiting prospective Renewable Technology
22 Resources entry an important piece of balancing state interest and market
23 efficiency in the FCM.

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Q: Why is 200 MW the appropriate limit?

A: Under a demand curve, as long as exempted renewable entry does not exceed average annual load growth, and consequent growth in the installed capacity requirement, there will not be systematic downward pressure on prices. The Renewable Technology Resources limit is therefore set at the ISO’s estimate of average annual load growth (net of energy efficiency) of 189 MW, plus an adjustment for the reserve margin required to meet the installed capacity requirement, resulting in 200 MW as a reasonable Renewable Technology Resources cap that also accommodates the states' renewable energy goals. By virtue of setting the Renewable Technology Resources limit at the estimate of annual load growth, Renewable Technology Resources entry, even in the unlikely event it occurs up to the cap value, can be expected primarily to displace the new entry required to meet load growth. In such a circumstance, an FCM in equilibrium would still be expected clear near Net CONE, and merchant entry would be required to meet retirements, which are expected to be significant—by some estimates, retirements in New England may exceed 6,500 MW by 2020.

Under the ISO’s vertical demand curve, it was critical that exempted renewable entry *not* meet expected load growth, because if it did, it could put significant downward pressure on capacity clearing prices due to the binary nature of prices set using a vertical demand curve: clearing the market using offer prices reflecting the cost of new entry from new resources was necessary to ensure that the market

1 set prices that reflected the need for new entry. Under a sloped demand curve, the
2 demand curve will ensure that the market clearing prices reflect the cost of new
3 entry if the market is near equilibrium whether new entrants have a zero price or a
4 price reflecting net CONE. Under a sloped demand curve, when the market is
5 long, binary pricing is much less of a concern, though renewable entry would be
6 expected to slow the market's return to equilibrium. If the market is short or at
7 equilibrium, this is not a concern.

8

9 **Q: Does the Renewable Technology Resources exemption result in buying more**
10 **capacity than needed?**

11 A: No. The Commission has concluded that it is unreasonable to design a capacity
12 market to procure more than the capacity target over the long term. Under the
13 Demand Curve Changes, the FCM would include Renewable Technology
14 Resources in the total resources procured under the demand curve; no additional
15 capacity would be procured.

16

17 **VIII. OTHER CONFORMING CHANGES**

18 **Q: What other revisions do the Demand Curve changes entail?**

19 A: In order to conduct FCA 9 with a sloped demand curve, the ISO is making a
20 number of conforming changes to the market rules. These include: revisions to
21 the FCA starting price (which is set equal to the price cap of the system-wide
22 demand curve so that the upper limit on supply offer prices is consistent with the
23 maximum price at which an offer could clear against the demand curve); revisions

1 to the total system capacity purchased in the FCA (the FCA will now purchase the
2 amount of capacity determined by the system-wide demand curve), and; changes
3 to various market clearing rules. The rule revisions also contain a nonsubstantive
4 change to the use of de-list bids in certain circumstances, replacing the practice of
5 using de-list bids as a means to limit the Capacity Supply Obligation a resource
6 may assume in the event there is a reduction in the capacity the resource is
7 capable of providing for the commitment period. The ISO has developed the
8 capability to administer these reductions during the qualification process that
9 occurs prior to the FCA.

10
11 **Q: DOES THIS CONCLUDE YOUR TESTIMONY?**

12 **A: Yes**

13
14
15 I declare under penalty of perjury that the foregoing is true and correct.

16
17
18 Executed on April 1, 2014

19
20 
21

22 Robert G. Ethier

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

ISO New England Inc.)	
)	Docket No. ER14-____-000
)	
)	

**TESTIMONY OF DR. SAMUEL A. NEWELL AND DR. KATHLEEN SPEES
ON BEHALF OF ISO NEW ENGLAND INC.
REGARDING A FORWARD CAPACITY MARKET DEMAND CURVE**

Our names are Dr. Samuel A. Newell and Dr. Kathleen Spees. We are employed by The Brattle Group, as Principal and Senior Associate, respectively. We submit this affidavit on behalf of ISO New England Inc. (ISO-NE) to describe the analytical foundation and approach we used to support the development of a system-wide capacity demand curve for ISO-NE's Forward Capacity Market (FCM).

As we explain in the body of our testimony, we worked with ISO-NE staff and stakeholders to: (1) define a set of design objectives and evaluation criteria with which to guide the development of the demand curve; (2) develop a number of candidate demand curves; (3) evaluate the performance of each potential demand curve under different system conditions and modeling assumptions; and (4) recommend a single demand curve after weighing performance tradeoffs. We believe that ISO-NE's proposed demand curve is a well-designed curve that strikes an appropriate balance among competing design objectives and will perform well under a range of market conditions that ISO-NE may face in the future.

Our qualifications as experts derive from our extensive experience evaluating capacity markets and alternative market designs for resource adequacy. Our practice in capacity market design for RTOs across North America and internationally has given us a broad perspective on the practical implications of nuanced market design rules under a range of different economic and policy conditions.¹ In New England, we have worked closely with ISO-NE staff on this and prior assignments to understand the Forward Capacity Market (FCM) at a detailed level.² We have also previously worked on a number of assignments

¹ For example, we have worked with regulators, market operators, and market participants on matters related to resource adequacy and investment incentives in PJM Interconnection, New York, Alberta, California, Texas, Midcontinent ISO, Italy, and Russia. See a more comprehensive description of these engagements in our resumes, which are included as attachments to ISO-NE's filing letter.

² See LaPlante, Dave, Hung-po Chao, Samuel A. Newell, Metin Celebi, and Attila Hajos. *Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements*. June 5, 2009.

with market participants from all sectors operating within the ISO-NE footprint, which has provided us insights on how changes to the capacity market construct may impact the business decisions and other interests of suppliers, customers, utilities, and state regulators in New England.

A subset of our market design work has been specifically related to the development and improvement of capacity market demand curves designed around different sets of objectives. Our experience in capacity demand curve design includes: (1) PJM capacity market reviews of 2008, 2011, and 2014 (ongoing) to review market performance, including an evaluation and statistical simulations of the performance of that market's Variable Resource Requirement (VRR) curve;³ (2) Italian capacity demand curve and market design development in 2012, including developing a value-based locational demand curve reflecting the value of capacity to customers; and (3) a study on the economics of reliability for the Commission in 2013, including calculating a value-based capacity demand curve designed to procure an economically optimal quantity of capacity from a risk-neutral societal perspective.⁴

I, Dr. Newell, am an economist and engineer with more than 15 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and market rules. Prior to joining The Brattle Group, I was the Director of the Transmission Service at Cambridge Energy Research Associates and previously a Manager in the Utilities Practice at A.T. Kearney. I earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in materials science and engineering from Stanford University, and a B.A. in chemistry and physics from Harvard College.

I, Dr. Spees, am an economic consultant with expertise in wholesale electric energy, capacity, and ancillary service market design and price forecasting. I earned a Ph.D. in Engineering and Public Policy and an M.S. in Electrical and Computer Engineering from Carnegie Mellon University, and a B.S. in Mechanical Engineering and Physics from Iowa State University.

Complete details of our qualifications, publications, reports, and prior experiences are set forth in our resumes, listed as attachments to ISO-NE's filing letter.

³ See Sections IV and V of our 2008 and 2011 PJM capacity market reviews respectively, for the review of PJM's VRR curve, in Pfeifenberger, Johannes, Samuel Newell, Robert Earle, Attila Hajos, and Mariko Geronimo. *Review of PJM's Reliability Pricing Model (RPM)*. June 30, 2008; and Pfeifenberger, Johannes, Samuel Newell, Kathleen Spees, Attila Hajos, and Kamen Madjarov. *Second Performance Assessment of PJM's Reliability Pricing Model*. August 26, 2011.

⁴ See Section IV.B for a derivation and discussion of a value-based capacity demand curve, from Pfeifenberger, Johannes P., Kathleen Spees, Kevin Carden, and Nick Wintermantel. *Resource Adequacy Requirements: Reliability and Economic Implications*. September 2013.

TABLE OF CONTENTS

I. Summary	4
II. Motivation for Implementing a Sloped Demand Curve	7
III. Conceptual Demand Curve Design	8
A. Design Objectives	8
B. Range of Demand Curves Evaluated	9
C. Detailed Specification of the Proposed System Demand Curve	10
IV. Probabilistic Modeling of Demand Curve Performance	13
A. Overview of Monte Carlo Model Structure	13
B. Supply Modeling	14
C. Administrative Demand and Transmission Parameters	17
D. Shocks to Supply and Demand	18
E. Reliability Outcomes	20
V. Performance of the Proposed Curve Compared to Alternative Demand Curves ...	21
A. Performance of the Proposed Curve Compared to a Vertical Demand Curve	21
B. Performance Compared to Other Pre-Defined Curves	23
C. Performance Compared to System-Wide Administrative Pricing Rules	26
D. Impact of Varying the Price Cap and Minimum Quantity	27
E. Impact of Varying Demand Curve Slope	30
F. Impact of Varying the Demand Curve Shape	33
G. Summary of Performance Compared to Alternative Curves	36
VI. Sensitivity to System Conditions and Modeling Uncertainties	38
A. Sensitivity to System Net CONE	38
B. Sensitivity to Administrative Errors in Net CONE	40
C. Sensitivity to the Magnitude of Supply and Demand Shocks	43
D. Interactions with ISO-NE's Pay for Performance Proposal	45
E. Summary of Performance under Sensitivity Scenarios	48
VII. Certification	50

I. SUMMARY

On January 24, 2014, the Commission ordered ISO-NE to develop a downward-sloping demand curve for use in the Forward Capacity Market (FCM), and to file it by April 1, 2014 for implementation in Forward Capacity Auction (FCA) 9, corresponding to the 2018/19 delivery year.⁵ In its two orders on that day, the Commission confirmed a number of important concerns that ISO-NE, its market monitor, and several stakeholders have identified with the current vertical demand curve, including: (a) volatile prices with a bimodal price distribution, caused by a vertical demand curve combined with the structurally steep supply curve that is characteristic of capacity markets; (b) a greater incentive and ability to exercise market power from both buy- and sell-side entities; and (c) price outcomes that shift abruptly as reserve margins change, rather than in a more gradual fashion that would be more proportional to the incremental value of capacity. Although ISO-NE's existing system-wide administrative pricing rules help address some of these concerns, they distort market prices and can lead to inefficient outcomes. A sloped demand curve would address the same concerns more effectively and efficiently. It would also form the basis for a more sustainable market design in which resource adequacy is achieved through market-based investment.

Having identified the need for a demand curve well before the Commission orders, ISO-NE retained us to assist in designing such a curve in early 2013. After establishing design objectives and engaging in preliminary analyses with ISO-NE, we presented a preliminary candidate curve to stakeholders at a meeting of the NEPOOL Markets Committee (MC) in January, 2014, along with a set of guidelines that described a range of well-performing curves that could be adopted. We solicited stakeholder input over the course of several more MC meetings and evaluated a number of alternative curves suggested, identifying several additional well-performing curves with different tradeoffs among design objectives. Finally, based on stakeholder ideas and further analysis, we refined the curve to the final version that ISO-NE has proposed in this filing, as shown in Figure 1.

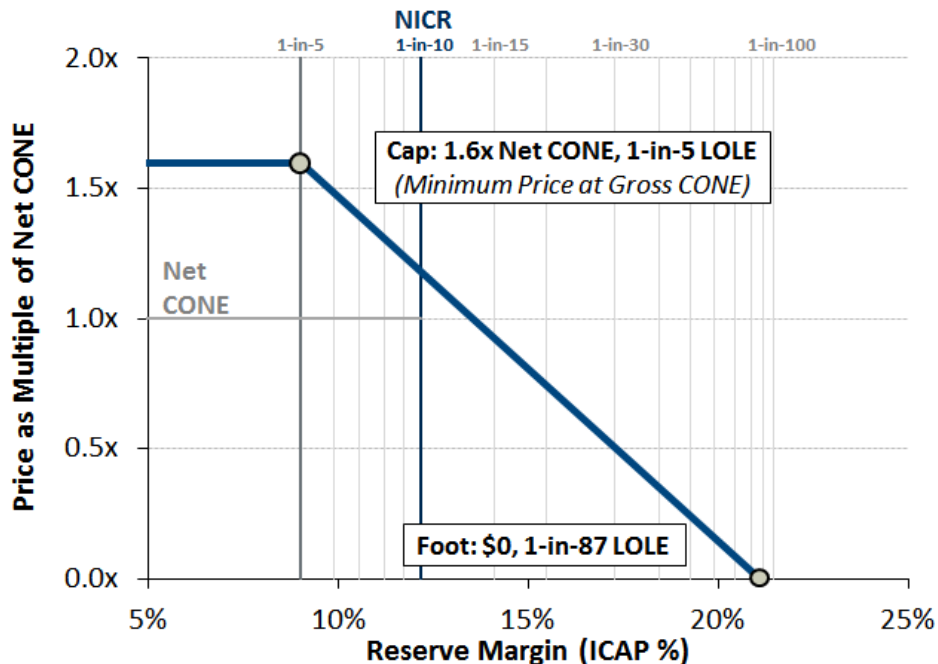
The curve is defined by a price cap at $1.6 \times$ the Net Cost of New Entry (Net CONE) and a quantity corresponding to a 1-in-5 Loss of Load Expectation (LOLE), with a downward-sloping line dropping to a zero price at a quantity corresponding to 1-in-87 LOLE.⁶ In the event that $1.6 \times$ Net CONE falls below $1 \times$ gross CONE, the cap becomes $1 \times$ gross CONE.⁷

⁵ See FERC Orders from January 24, 2014 in Dockets EL14-7-000 and ER14-463-000.

⁶ The Newell/Ungate Testimony attached to this same filing calculates a Net CONE value of \$11.08/kW-month for FCA9 based on a combined-cycle reference technology.

⁷ "Gross CONE" is the total cost of new entry before subtracting estimated energy and ancillary services (E&AS) margins and other revenue offsets to calculate Net CONE.

Figure 1
ISO New England Proposed System Demand Curve



Notes:

Reserve Margin quantities as a percentage of ICAP are based on FCA7. See ISO-NE, Summary of Historical ICR Values, posted at: http://iso-ne.com/markets/othrmkts_data/fcm/doc/summary_of_icr_values%20expanded.xls

Our approach to developing a demand curve for New England started with a clear set of design objectives. The primary objective is to maintain the existing resource adequacy standard of 1-event-in-10-years loss of load expectation (LOLE). However, recognizing that a sloped demand curve will produce a range of reserve margins, we established with ISO-NE that reserve margins could fall below the 1-in-10 level in any single year as long as the market maintains 1-in-10 on a long-term average basis and rarely falls below 1-in-5 in any given year (a level below which ISO-NE is more likely to act to bolster resource adequacy through means outside of the market). Other objectives include mitigating price volatility, reducing susceptibility to market power, and building robustness to changes in market conditions and modeling uncertainties. We did *not* attempt to design a curve that reflects the marginal economic value of capacity, which would produce results inconsistent with the 1-in-10 resource adequacy standard.

We evaluated a wide range of candidate curves against these design objectives, including other RTOs' curves, ISO-NE's prior Locational Installed Capacity (LICAP) proposal, various straight-line and convex curves, and stakeholder proposals. To compare these various curves' performance in several dimensions, we developed a Monte Carlo model that estimates the likely distribution of price, quantity, and reliability outcomes under each demand curve. Our model incorporates a realistic supply curve, an administrative demand curve, locational capacity auction clearing mechanics, and stochastic shocks to supply and demand. In each case we also model economic entry of supply until the long-term average price converges to the Net CONE, such that a rational supplier would earn an adequate return on investment. Under this standard long-term economic equilibrium assumption, all

candidate curves achieve the same average price. The curves differ in the average reliability, frequency of low reliability events, and price volatility they produce.

One of the most important components of this design exercise is to rule out poorly performing curves that would not meet the reliability objectives or would produce extreme pricing volatility or sensitivity to changing conditions. Our simulation tool also allowed us to develop a number of candidate curves that exactly met the 1-in-10 reliability objective by adjusting one or more parameters. After developing a number of candidate curves calibrated to meet the 1-in-10 objective, we were able to compare their performance relative to other design objectives.

By design, all calibrated candidate curves achieve the same average reliability and the same *average* prices. However, differently-shaped curves show a range of results under other performance metrics, with improvements in one dimension tending to introduce performance tradeoffs elsewhere. For example, our simulations show substantial differences in the *volatility* of prices, with steeper curves and higher price caps causing greater volatility. Reducing this price volatility with flatter curves and lower price caps comes at the expense of introducing a greater risk of low reliability outcomes when running sensitivity analyses with Net CONE estimation error or larger shocks. While we have identified a number of well-performing curves, there is no curve that is superior in all respects, and so tradeoffs are necessary.

The final proposed curve strikes a good balance. Our simulations demonstrate that it achieves 1-in-10 on average with reliability less than 1-in-5 only 7% of the time, compared to as much as 30% for other curves. Its flatter slope and lower price cap than some alternatives help reduce price volatility and susceptibility to market power abuse. Top quintile annual capacity procurement costs are 46% above average, compared to as much as 96% for some curves with higher caps. If Net CONE is understated by 20%, the proposed curve misses reliability objectives with a 68% higher LOLE (steeper curves and convex curves perform somewhat better in this regard with the tradeoff of incurring greater price volatility). Other advantages are that the $1 \times$ gross CONE minimum on the cap reduces sensitivity to Net CONE estimation error when the Energy and Ancillary Service (E&AS) offset is large. The curve is fairly robust to changes in market conditions, although periodic reassessment will be valuable.

The recommended curve would be used for the system-wide demand in forward capacity auctions. A demand curve for annual reconfiguration auctions intended to work with the proposed demand curve will be developed in a future stakeholder process. As for the import- and export-constrained zones, ISO-NE has not yet proposed demand curves due to limited time to work through the details with stakeholders. We expect that ISO-NE will file zonal curves for the following auction. Until then, for FCA9, the zones would continue to be modeled with vertical curves.

II. MOTIVATION FOR IMPLEMENTING A SLOPED DEMAND CURVE

On January 24, 2014, the Commission ordered ISO-NE to develop a downward-sloping demand curve for use in the FCM, and to file it by April 1, 2014 for implementation in FCA9, corresponding to the 2018/19 delivery year.⁸ These Commission orders confirmed a number of important concerns that ISO-NE, its market monitor, and several stakeholders have identified with the current vertical demand curve, including: (a) volatile prices with a bimodal price distribution, caused by a vertical demand curve combined with the structurally steep supply curve that is characteristic of capacity markets; (b) a greater incentive and ability to exercise market power from both buy-and sell-side entities; and (c) price outcomes shift abruptly as reserve margins change rather than in a more gradual fashion that would be more proportional to the incremental value of capacity.

ISO-NE's existing system-wide administrative pricing rules partially address some of the performance concerns with a vertical demand curve.⁹ These rules help mitigate price volatility by overriding the auction clearing price with administratively-determined prices when triggered by certain shortage condition tests. However, these rules also introduce their own inefficiencies and performance concerns by producing market incentives that can deviate from market fundamentals, and by introducing price discrimination between new and existing resources. Consequently, these rules reduce the efficiency of market clearing results and distort incentives for investing in new resources and re-investing in existing resources.

Concerns about the existing market's exposure to bimodal pricing and inefficient administrative pricing rules have been highlighted by the auction clearing results of FCM, particularly in the last two auctions.¹⁰ For many years, the market cleared at the administrative price floor in every location, which resulted in sustaining an uneconomically large excess of supply for several years and even attracting additional supply into an already long market in some years. However, in the past two auctions the market has seen an abrupt shift in the supply-demand balance caused by the removal of the price floor and other economic drivers. The consequence was a step-change in clearing prices from the floor to the cap, first in the NEMA-Boston zone in FCA7 and then system-wide in FCA8.¹¹ In both auctions, administrative pricing rules were triggered, overriding these clearing prices for existing resources. These results provide illustrative examples of the bimodal outcomes that must be expected to occur under a vertical demand curve, as well as the sometimes uneconomic and counterintuitive consequences of the administrative pricing rules as we discuss further in Section V.B below.

⁸ Federal Energy Regulatory Commission (2014) "Order Accepting, Subject to Condition, Exigent Circumstances Revision," Issued January 24, 2014. Docket No. ER14-463-000. Retrieved from http://iso-ne.com/regulatory/ferc/orders/2014/jan/er14-463-000_1-24-14_exigent_circum_order.pdf

⁹ ISO-NE's two system-wide administrative pricing rules are the Inadequate Supply and Insufficient Competition Rules. A third rule, the Capacity Carry Forward Rule, applies only at the zonal level. See ISO-NE Market Rule 1, Sections III.13.2.8.1, III.13.2.7.9, and III.A.21.1.

¹⁰ See ISO-NE, FCM Results, posted at: http://iso-ne.com/markets/othrmkts_data/fcm/cal_results/index.html

¹¹ *Id.*

A final, but less understood, concern with the current vertical demand curve is that it will not achieve ISO-NE's 1-in-10 LOLE reliability standard on a long-run average basis. The current curve is vertical at the Net Installed Capacity Requirement (NICR), which is the quantity of capacity that ISO-NE would need to achieve 1-in-10 if that were the exact quantity in the market in every year. However, while the vertical curve will procure NICR in most years, there will be some years when there is a shortage of supply offers and prices clear at the price cap. In fact, these shortage years have to be relatively frequent if prices are to be high enough on average to attract new generation investments. These shortage years then bring down system reliability on average, and are not offset by higher-reliability years since the vertical curve will not procure excess supplies under any conditions. A sloping demand curve, if well designed, can provide an appropriate balance between shortage and surplus conditions that addresses this concern along with the other concerns noted above.

III. CONCEPTUAL DEMAND CURVE DESIGN

We describe here the conceptual approach we used to develop the downward-sloping capacity demand curve that ISO-NE proposes to implement in FCM. The curve is designed to meet the ISO's reliability objectives in a market environment where it must be possible to build new generation on a merchant basis. We worked with ISO-NE staff and the NEPOOL stakeholder community to establish design objectives, construct a range of candidate demand curves, evaluate performance tradeoffs among these curves, and incorporate lessons learned from ISO-NE and other capacity markets' experience to date. The final proposed demand curve incorporates these various inputs and strikes a balance among sometimes competing design objectives and stakeholder priorities.

A. Design Objectives

As a starting point for developing a capacity demand curve, we worked with ISO-NE staff to establish design objectives and later refined these objectives through a stakeholder process. Consistent with the design objectives of ISO-NE's capacity market, we established that the primary design objective is to maintain reliability and achieve the 1-in-10 LOLE reliability standard. However, we also considered a number of other objectives, including:

- **Reliability**
 - Maintain 1-in-10 LOLE target on a long-term average basis, although LOLE in any one year may fall below the target; and
 - Rarely fall into extreme low-reliability events, measured at a reserve margin corresponding to a 1-in-5 LOLE level where ISO-NE is more likely to administratively intervene in the market.
- **Prices**
 - Reduce susceptibility to the exercise of market power;
 - Reduce price volatility impact from small variations in market conditions and administrative parameters, including lumpy investment decisions, demand forecast changes, and transmission parameters; and

- Limit the frequency of outcomes at the administrative price cap.
- **Robustness**
 - Perform well under a range of market conditions, changes in administrative parameters and administrative estimation errors.

Several of these design objectives are inherently difficult to satisfy, and in many cases we must weigh tradeoffs among competing design objectives. For example, capacity markets can be expected to produce structurally volatile prices due to steep supply and demand curves, meaning that small changes in supply or demand can cause large changes in price. Introducing a sloped demand curve will mitigate some of this price volatility, with flatter curves resulting in more stable prices. However, a very flat demand curve will introduce tradeoffs in other objectives by introducing greater quantity uncertainty and greater risk of low-reliability outcomes. We further explain the tradeoffs among these design objectives as we compare the performance of the proposed and alternative demand curves.

We also note that defining our primary design objective as achieving 1-in-10 LOLE on average over many years narrows the possibility space of demand curves that ISO-NE might have considered. For example, some stakeholders proposed curves consistent with entirely different design objectives such as: (1) developing a curve that would reflect the declining marginal economic value of capacity to customers as the reserve margin increases, which would be economically efficient but might not achieve 1-in-10; or (2) developing a curve that always procures enough to achieve at least 1-in-10, as opposed to meeting 1-in-10 on average. We acknowledge that these alternative approaches have various benefits that make them more or less appealing to individual stakeholders, and also acknowledge that other RTOs or regulators might adopt different approaches better suited to their underlying policy or market design objectives. We do not attempt to compare these approaches for the purposes of this study, but instead adopt a 1-in-10 average LOLE as stipulated by ISO-NE as the design objective that most closely matches the founding principles and design objectives of its Forward Capacity Market.

B. Range of Demand Curves Evaluated

In working with ISO-NE and stakeholders to develop the proposed curve, we considered and compared the performance of a wide variety of candidate demand curves including: (a) the current vertical curve, as well as alternative vertical curves with different price caps or right-shifted quantities; (b) previously-defined curves, including the curves currently implement in PJM and NYISO, as well as the curve that ISO-NE submitted as part of its original Locational Installed Capacity (LICAP) market proposal in 2004; (c) newly-defined curves with a variety of shapes, slopes, price caps, and quantity points, including a range of curves with parameters tuned to meet 1-in-10 on average; and (d) stakeholder-proposed curves consistent with various reliability and cost objectives.

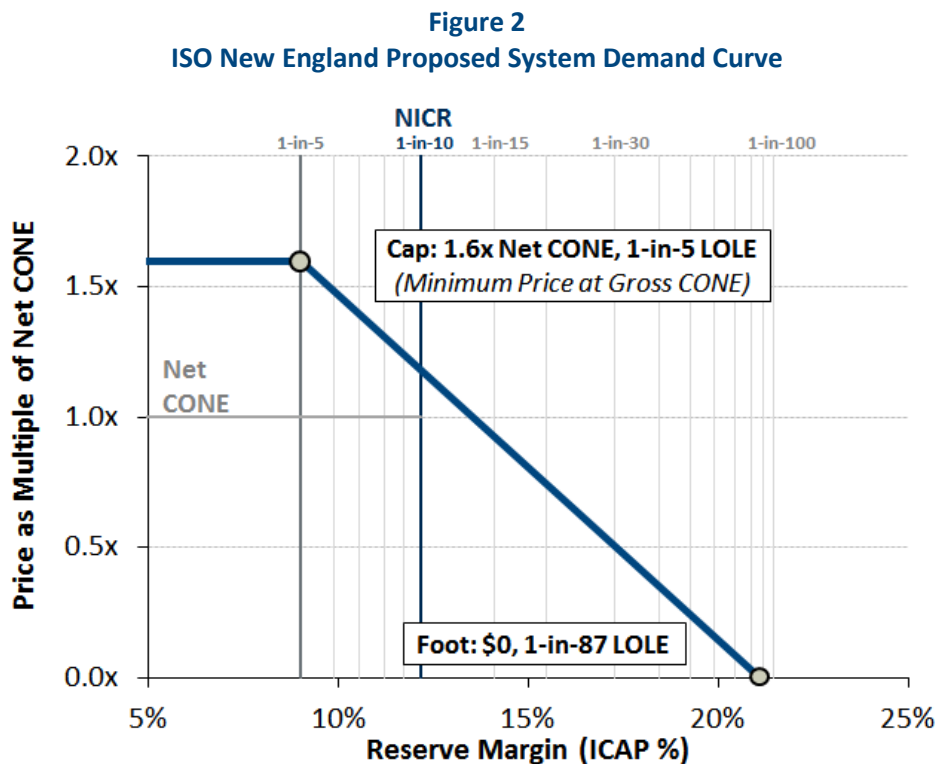
Overall, we evaluated the performance of many dozens of possible demand curves, starting with a wide initial “possibility space.” From this wide range of curves, we identified a number of well-functioning curves that are consistent with the design objectives, but that reflect different performance tradeoffs. We provide a review of these performance tradeoffs for a subset of the alternative curves we evaluated in Section V below.

C. Detailed Specification of the Proposed System Demand Curve

The capacity demand curve proposed by ISO-NE is defined by the prices and quantities at two points, the cap and foot, as summarized in Figure 2 and Table 1. While we report these quantities and prices in several equivalent ways consistent with the parameters of FCA7, in future auctions the points would be defined as follows:

- **The Cap** at (a) a price at the maximum of $1.6 \times$ Net CONE or gross CONE, and (b) a quantity at 1-in-5 LOLE.
- **The Foot** at (a) a price of zero, and (b) quantity at 1-in-87 LOLE.

Probably the most important feature of the curve is the placement of the price cap, which incorporates a number of considerations that we have evaluated along with ISO-NE staff and stakeholders. In general, the price cap and entire demand curve must be high enough to attract a sufficient quantity of supply to meet the 1-in-10 reliability standard, assuming prices will converge to Net CONE on a long-run average basis. Curves with a substantial range of price caps can meet this objective, but, as discussed further in Section V.D below, the selected price cap reflects a balance between: (a) objectives to reduce price volatility and susceptibility to market power exercise, both of which are served by lowering the price cap; and (b) objectives to provide strong price incentives to maintain reliability during shortage periods and limit the number of events at low reliability levels, which are better served by increasing the price cap.



Notes:

Quantity parameters reported consistent with FCA7.

Table 1
ISO New England Proposed System Demand Curve

Parameter	Cap	NICR	Foot
Price (\$/kW-m)	\$17.73	\$13.16	\$0.00
Corresponding RM in FCA 7	9.0%	12.1%	21.1%
Reliability Index (1-in-x)	1-in-5	1-in-10	1-in-87
% of NICR	97.2%	100.0%	108.0%

Notes:

Quantity parameters consistent with FCA7.

Reliability data based on GE MARS Modeling provided by ISO-NE.

In our evaluation of a broad spectrum of curves, we identified well-performing curves with price caps over a range of $1.5 \times$ Net CONE to $2 \times$ Net CONE. Curves with higher price caps tended to increase price volatility and susceptibility to market power abuse without materially improving other metrics. Conversely, curves with lower price caps tended to introduce an unacceptably high frequency of low reliability events, especially if Net CONE is underestimated.

Balancing the performance tradeoffs and based on stakeholder input, ISO-NE selected a price cap at $1.6 \times$ Net CONE. The primary reasons for selecting a point near the lower end of that range are that: (a) the price cap will be similar to that adopted in PJM at $1.5 \times$ Net CONE and in NYISO at $1.5 \times$ gross CONE (equivalent to approximately $1.9 \times$ Net CONE using ISO-NE gross and Net CONE parameters);¹² (b) the cap would be calculated at \$17.73/kW-month in FCA9 based on the proposed Net CONE of \$11.08/kW-month, reflecting a substantial increase above the most recent FCA8 price cap of \$15.82/kW-month (a bigger increase in this parameter was perceived as undesirable by some stakeholders);¹³ and (c) selecting a cap at the lower end of the well-functioning range provides more substantial benefits for mitigating price spikes, price volatility, and mitigating the potential for exercise of market power.

The quantity of the cap point is at 1-in-5 LOLE, consistent with guidance provided by ISO-NE on the “minimum acceptable” reliability level below which ISO-NE would be more likely to intervene in the market. Setting the price cap at this quantity or higher ensures that FCM will be sending the strongest price signals for incremental supply as the system

¹² The ISO-NE proposed cap is also within the range of PJM and NYISO’s caps when compared in absolute terms, when converting to the same units of \$/kW-month in installed capacity (ICAP) units for the closest delivery year for which the other markets’ parameters have been calculated. The absolute comparison is: (a) \$17.73/kW-month in ISO-NE for 2018/19; (b) \$13.47-\$16.09/kW-m across PJM capacity zones for 2017/18; and (c) \$14.10-\$27.31/kW-m across NYISO capacity zones for 2016/17. See PJM’s Manual 18, Section 3; PJM 2017/18 Planning Period Parameters; NYISO Installed Capacity Manual, Section 5.5; and NYISO 2014-2017 Demand Curve Parameters and Demand Curves.

¹³ See ISO-NE, FCA8 Pricing Thresholds, posted at: http://iso-ne.com/markets/othrmkts_data/fcm/doc/index.html

approaches this shortage level, and also means that there will be in-market opportunities for procuring those supplies prior to any intervention to procure emergency supplies on an out-of-market basis.

The proposed curve also adopts a minimum constraint that prevents the price cap from falling below $1.0 \times$ gross CONE, which is identical to a feature that the Commission has recently approved for PJM's variable resource requirement curve.¹⁴ As in PJM, this minimum constraint on the price cap is not expected to bind under near-term market conditions in New England. However, in future years there may be cases when high energy prices could substantially increase the energy and ancillary services (E&AS) offset and drive Net CONE much lower. Under those conditions the entire demand curve could collapse to zero or near-zero levels, introducing much greater risks of low reliability events and consequences from the possibility of underestimating Net CONE as we explain further in Section VI.

Given the placement of the price cap and a simple linear shape, we calculated the quantity of the foot point at 1-in-87 LOLE (corresponding to 108% of NICR) such that the overall curve will achieve the 1-in-10 LOLE design objective on average across years.

We also considered other curve shapes and found a number of theoretical and practical advantages to "kinked" curves that are convex to the origin as explained in Section V.E, but such curves tended to perform better if combined with higher price caps. Overall, ISO-NE and stakeholders opted to select a simple straight curve with a price cap toward the lower end of the well-performing range because this curve will provide the most price volatility mitigation and protection against the exercise of market power compared to curves with a more convex shape.

Updates to these price and quantity points would be completed annually prior to each Forward Capacity Auction (FCA). The quantity points are defined based on the same reliability modeling analysis that ISO-NE already conducts in its annual Installed Capacity Requirement (ICR) study, although an additional component of that study will be needed to calculate the 1-in-5 quantity and 1-in-87 quantity points as well as the quantity for NICR at 1-in-10.¹⁵ Each FCA and reconfiguration auction (RA) would use the most up-to-date quantity numbers as estimated in the most recent ICR study. The Net CONE parameter used to define the price cap would be updated over time.¹⁶

¹⁴ See the Commission's Order on January 30, 2012 in Docket No. ER12-513-000, pp. 24-28.

¹⁵ The most recent ISO-NE LOLE study for Capacity Commitment Period 2017/18 is posted at http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2014/icr_2017_2018_report_final.pdf

¹⁶ For a more detailed description of the proposed approach to annual updates in the administrative Net CONE parameter, see the concurrently filed Newell/Ungate Testimony.

IV. PROBABILISTIC MODELING OF DEMAND CURVE PERFORMANCE

Different demand curves with different shapes and slopes would naturally produce more or less reliability and higher or lower price volatility. We evaluate the performance of alternative demand curves using a Monte Carlo simulation to calculate the likely distribution of price, quantity, and reliability outcomes that might be realized under each different demand curve. In this Section, we describe the primary components of this model, including our characterization of supply, demand, transmission, reliability, and auction clearing. We present simulation results under alternative demand curves and scenario assumptions in the following Sections V and VI.

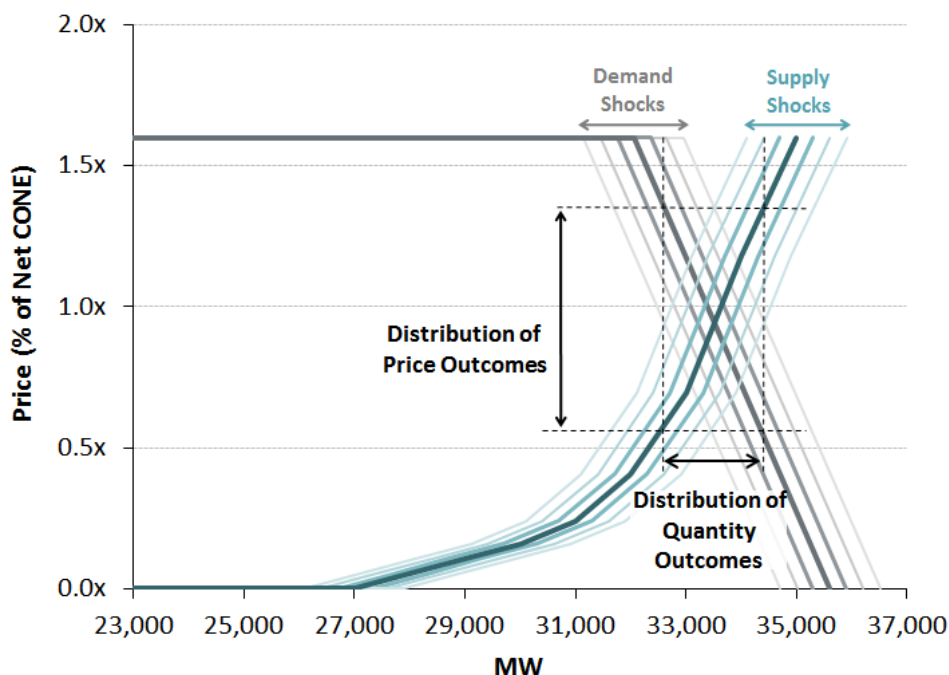
A. Overview of Monte Carlo Model Structure

To evaluate the performance of candidate demand curves over the long term, we simulate a distribution of 1,000 capacity market outcomes using a Monte Carlo analysis. This analysis allows us to estimate a distribution of price, quantity, and reliability outcomes for candidate curves, and compare these outcomes to the design objectives described in Section III.A.

Our model provides meaningful indicators of performance because its mechanics and inputs are informed by actual capacity market experience. We use a locational clearing algorithm to calculate cleared prices and quantities based on supply and demand curves, just as ISO-NE would in the auctions. Supply curves reflect the shapes we observe from historical three-year forward capacity auctions in ISO-NE and PJM. Administrative demand in each location reflects a shape that we specify.

To calculate a distribution of potential price and quantity outcomes, we conduct a Monte Carlo simulation with each draw applying realistic shocks to supply and demand based on variations observed in ISO-NE's first seven forward capacity auctions.¹⁷ A stylized depiction of the price and quantity distributions driven by supply and demand shocks is shown in Figure 3 below, with the intersection of supply and demand determining price and quantity distributions under a particular demand curve. We also assume economically rational new entry, with new supply added infra-marginally until the long-term average price equals Net CONE, neither more nor less.¹⁸ As such, our simulations reflect long-term conditions at economic equilibrium on average, and do not reflect a forecast of outcomes over the next several years or any other particular year.

Figure 3
Stylized Depiction of Supply and Demand Shocks in the Monte Carlo Analysis



Note:

Illustrative shocks are not intended to reflect the exact degree of shocks we apply in our simulations.

B. Supply Modeling

The supply curve shape is an important driver of volatility in cleared price and quantity in our modeling, as in real capacity markets. A gradually-increasing, elastic supply curve will result in relatively stable prices and quantities near the reliability requirement even

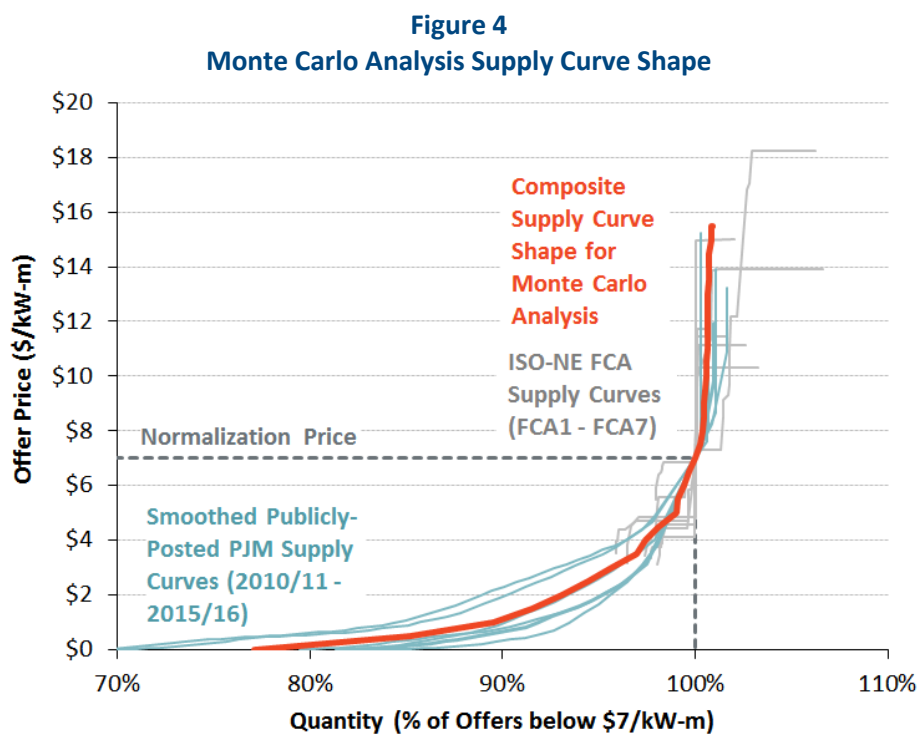
¹⁷ Each draw is modeled independently, not as a time-series.

¹⁸ An alternative approach would have been to model new supply as a long, flat shelf on the supply curve set at Net CONE, but that would be inconsistent with the range of offers we have observed for actual new entrants in various capacity markets, and it would artificially eliminate price volatility. Our modeling approach reflects the fact that short-run capacity supply curves are steep, resulting in structurally volatile prices, while long-run prices converge to long-run marginal costs, or Net CONE.

in the presence of shocks to supply and demand, while a steep supply curve will result in greater volatility.

We use historical FCM offer prices and quantities to create a realistic supply curve shape, in combination with historical supply curves from PJM's Base Residual Auctions (BRA).¹⁹ The price floors that were in effect in FCAs 1-7 precluded the discovery of offers below the floor, so we used PJM supply curves as a proxy to construct the portion of the supply curve shape at lower prices.

To construct a single composite shape from the individual historical supply curves, we first normalize each curve by the quantity of offers made below \$7/kW-month.²⁰ We then combine the normalized individual curves into a composite supply curve shape by taking the average quantity at each price level as shown in Figure 4. Consistent with the supply curve shapes we observe over historical capacity auction, the resulting composite supply curve is relatively steep, especially at prices greater than \$5/kW-month.



Sources and Notes:

Historical ISO-NE FCA supply curves provided by ISO-NE; PJM supply curves from Pfeifenberger, *et al.* (2011), p. 21. *The Second Performance Assessment of PJM's Reliability Pricing Model.*
Historical offers inflated by Handy-Whitman Index.

¹⁹ Historical ISO-NE offer data were provided by ISO-NE staff, PJM data are from Pfeifenberger, *et al.* (2011), p. 21. Available: http://www.brattle.com/system/publications/pdfs/000/004/833/original/Second_Performance_Assessment_of_PJM's_Reliability_Pricing_Model_Pfeifenberger_et_al_Aug_26_2011.pdf?1378772133

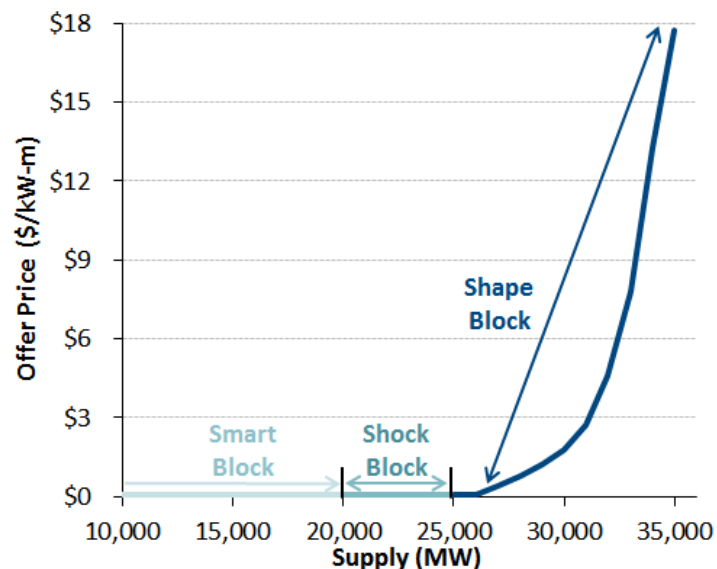
²⁰ This normalization price was chosen because it resulted in relatively consistent shapes across the individual supply curves.

We also reflect the lumpy nature of investments by simulating each supply curve as a collection of discrete sized offer blocks. Simply modeling a smooth offer curve as shown in Figure 4 would somewhat understate realized volatility in price and quantity outcomes. We derive offer block sizes using a random selection of cleared resources from each location in FCA7, with a different selection used in each Monte Carlo simulation draw.

To simulate rational economic entry, we increase or decrease the quantity of zero-priced supply under each demand curve so that the average clearing price over all draws is equal to Net CONE. This normalization allows us to examine the performance of each demand curve in a long-term equilibrium state. Too much zero-priced supply would result in an average price below Net CONE, while too little supply would result in a price above Net CONE.

The block of zero-priced supply used for normalization is shown as the “Smart Block” in Figure 5. The quantity of supply in the smart block is held constant across individual draws, but is slightly different between demand curves. For example, with a right-shifted demand curve, more supply is included in the smart block than with our proposed curve (if the same smart block were used to model both curves, then clearing prices with the right-shifted curve would be higher than with our proposed curve). In contrast to the smart block, the quantity of the shock block varies with each draw to generate shocks to the supply curve, as described in Section IV.D.

Figure 5
Stylized Depiction of Simulated Supply Curve Components



C. Administrative Demand and Transmission Parameters

We reflect administrative demand curves at both a system and local level in a locational clearing algorithm that minimizes capacity procurement costs subject to transmission constraints. Table 2 summarizes the demand and transmission parameters applicable from FCA7, which we use as the base values in our modeling before applying shocks.

At the system level, we apply a number of different demand curves as explained throughout this testimony. However, to realistically depict overall clearing distributions, we must also capture locational clearing mechanics that are affected by locational demand curves. While ISO-NE is not in the present filing submitting proposed locational demand curves, we understand that it will do so in the near future. Absent a firm proposal on the shape of these locational demand curves, we assume that each location will have the same shape demand curve as in the system, if expressed as a proportion of the local demand.²¹ Revising the shape of these assumed locational curves would have only a modest impact on the system-wide results presented in this testimony.²²

Table 2
FCA7 Reliability Requirements and Transfer Limits

Reliability Requirements		
System Net Installed Capacity Requirement	(MW)	32,968
CT Local Sourcing Requirement	(MW)	7,603
NEMA/Boston Local Sourcing Requirement	(MW)	3,209
ME Maximum Capacity Limit	(MW)	3,709
Transmission Transfer Capabilities		
CT Import Limit	(MW)	2,600
NEMA/Boston Import Limit	(MW)	4,850
ME - NH Interface Limit	(MW)	1,600

Sources and Notes:

ISO-NE, Summary of Historical ICR Values, posted at:

http://iso-ne.com/markets/othrmkts_data/fcm/doc/summary_of_icr_values%20expanded.xls

²¹ Specifically, expressed as a fraction of the Local Sourcing Requirement (LSR) plus Total Transfer Capability (TTC) in the two import-constrained zones, and as a fraction of the Maximum Clearing Limit (MCL) in the export-constrained zones.

²² For example, we assume that the export-constrained zone may clear excess supply above MCL in some cases, which results in a somewhat lower realized reliability on a system-wide basis because the reliability value of supply sourced in export-constrained zones decreases at quantities above MCL.

D. Shocks to Supply and Demand

To simulate a realistic distribution of price, quantity, and reliability outcomes, we include upward and downward shocks to both supply and demand, with the magnitude of the shocks based on historical observation, as summarized in Table 3 and Figure 6.

Negative supply shocks could reflect the retirement of existing resources, while positive shocks might reflect low-priced entry of new resources or expanded interties. As summarized in Table 3, we assume that supply shocks are normally distributed, with a standard deviation equal to the standard deviation in supply offers below the price cap across FCAs 1–7. We note that with historical data limited to just seven auctions, the entry or exit of individual resources in a single auction (such as the exit of Salem Harbor from NEMA in FCA5) drives much of the observed variation, especially in smaller zones. We examine the sensitivity of the proposed demand curve’s performance to alternative supply shocks in Section VI.C.

Similarly, demand shocks could be driven by increases or decreases in the load forecast or LOLE modeling results. We assume that demand shocks are normally distributed with a standard deviation equal to the standard deviation observed in the reliability requirements across FCAs 1–7, as shown in Table 3.

Table 3
Standard Deviation in Supply and Demand Shocks
 Calculated based on Supply and Demand Quantities Over, FCAs 1–7

	Standard Deviation in Supply Shocks (MW)	Standard Deviation in Demand Shocks (MW)
Rest of System	327	n/a
CT	486	387
NEMA/Boston	387	567
ME	148	287
Total System	721	567

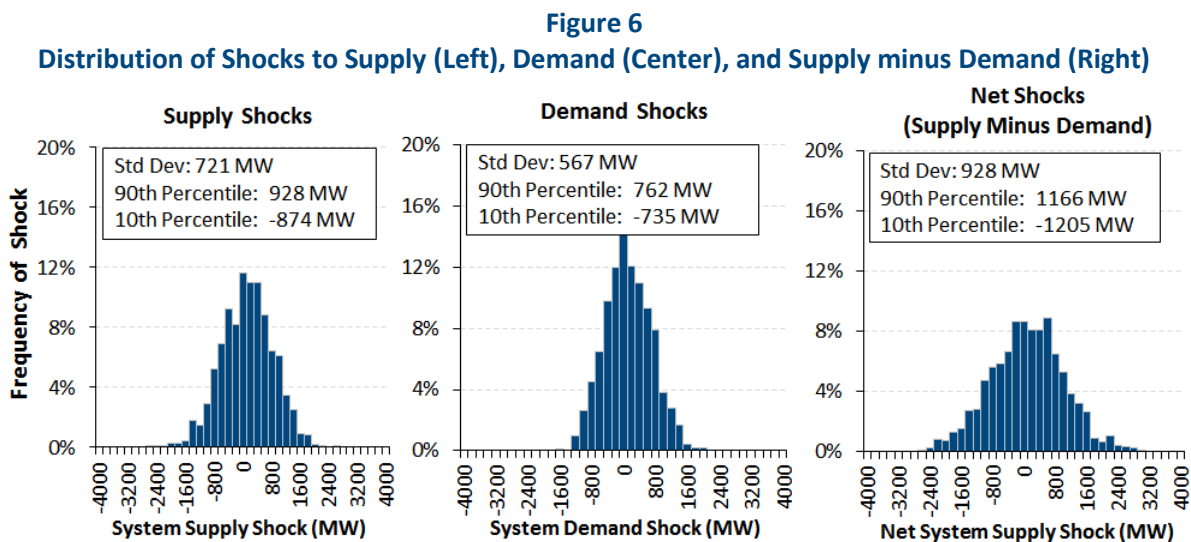
Sources and Notes:

Supply shocks calculated as the standard deviation in offers below the cap over FCAs 1-7, based on ISO-NE FCA offer data.

Demand shocks calculated as the standard deviation in NICR, LSR, and MCL over FCAs 1-7, from ISO-NE, Summary of Historical ICR Values, posted at: http://iso-ne.com/markets/othrmkts_data/fcm/doc/summary_of_icr_values%20expanded.xls

Our Monte Carlo simulations implement local supply and demand shocks independently. The aggregate supply shock at the system level is the sum of each locational shock, while locational shocks are calculated separately, with zonal shocks drawn independently from the aggregate system-wide shock to NICR. The distributions of system-wide supply and demand shocks across 1,000 draws of the Monte Carlo simulations are shown as the left and center charts in Figure 6.

Some stakeholders commented that assuming independence might overstate net system shocks (*i.e.*, the supply shock minus the demand shock) that drive the variation in clearing outcomes. However, we verified that our net shocks are consistent with FCA1–7. Our simulated distribution of net shocks is shown in the right chart of Figure 6 showing a standard deviation of 928 MW. This compares with actual realized standard deviations of 1,080 MW and 2,036 MW in supply minus demand across FCAs 1-7 and 1-8 respectively.²³

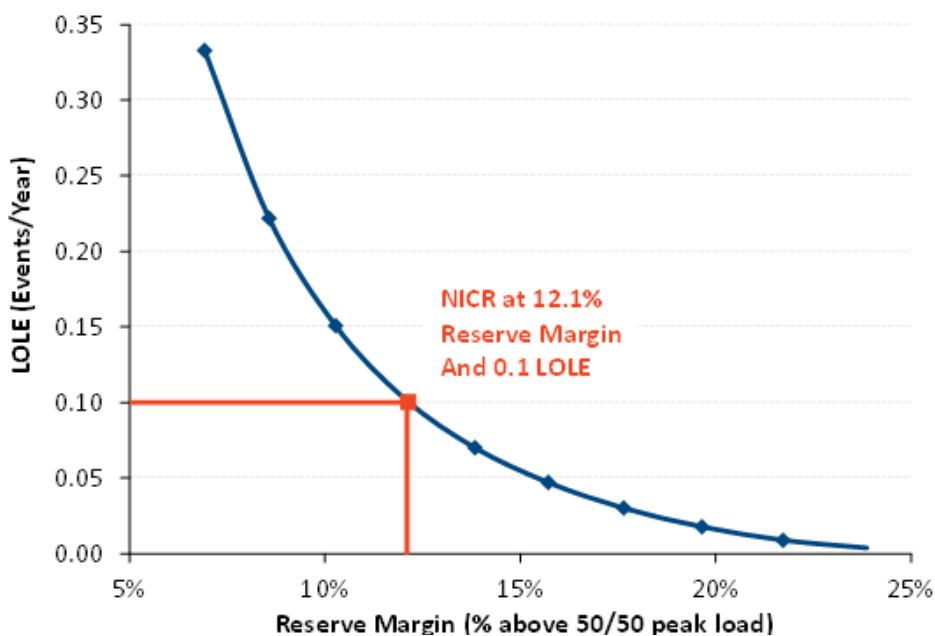


²³ The large increase in standard deviation when including FCA8 is caused by a large contraction in supply for that auction, driven by a number of economic factors including the elimination of the price floor. Quantities of supply offered below the cap were provided by ISO-NE. Historical NICR quantities are posted at: http://iso-ne.com/markets/othrmkts_data/fcm/doc/summary_of_icr_values%20expanded.xls

E. Reliability Outcomes

We calculate reliability outcomes for each Monte Carlo simulation draw based on reliability simulations conducted by ISO-NE staff. To support this analysis, ISO-NE staff conducted a series of simulations to estimate the relationship between the reserve margin and the LOLE, consistent with the analysis used to determine the NICR in FCA7.²⁴ Figure 7 shows the relationship between reserve margins and LOLE and highlights that the relationship is asymmetrical, with reliability outcomes deteriorating sharply at reserve margins below NICR but improving only gradually at reserve margins above NICR. An important implication of this asymmetry is that a demand curve that results in a distribution of clearing outcomes centered on NICR with equal variance above and below NICR, will fall short of the 0.1 LOLE target on an average basis.²⁵

Figure 7
LOLE vs. Reserve Margin



Sources and Notes:

LOLE data provided by ISO-NE staff, with interpolation between discrete points.

²⁴ The LOLE at the NICR reserve margin of 12.1% is 0.1.

²⁵ In our analyses, the average LOLE reported for a given demand curve is calculated as the average of the LOLE at the cleared reserve margin in each individual draw, rather than the LOLE at the average cleared reserve margin across all draws.

V. PERFORMANCE OF THE PROPOSED CURVE COMPARED TO ALTERNATIVE DEMAND CURVES

In this Section, we compare the performance of ISO-NE’s proposed demand curve to its current vertical curve and a range of alternatives. As we explain above, we have identified a range of well-performing demand curves that are consistent with the design objectives but reflect different tradeoffs among the multiple design objectives described in Section III.A. To illustrate the tradeoffs and explain how the proposed curve strikes a balance among competing objectives, we compare the performance of the proposed curve to a subset of the alternative curves we evaluated, including curves with different price caps, slopes, and shapes. While there are other curves that perform better than the proposed curve on some of the metrics we use to evaluate performance, we did not identify any curves that perform better in all dimensions.

A. Performance of the Proposed Curve Compared to a Vertical Demand Curve

As a starting point to our analysis, we compare the performance of the proposed demand curve to the performance of a vertical demand curve with the same price cap, at $1.6 \times$ Net CONE. Simulation results for these curves using the Monte Carlo model described in Section IV are summarized in Figure 8 and Table 4 below. The figure shows the distribution of price and quantity outcomes with each vertical curve, with additional performance metrics summarized in the following table.

Figure 8
Simulated Price and Quantity Outcomes with Vertical and Proposed Demand Curves

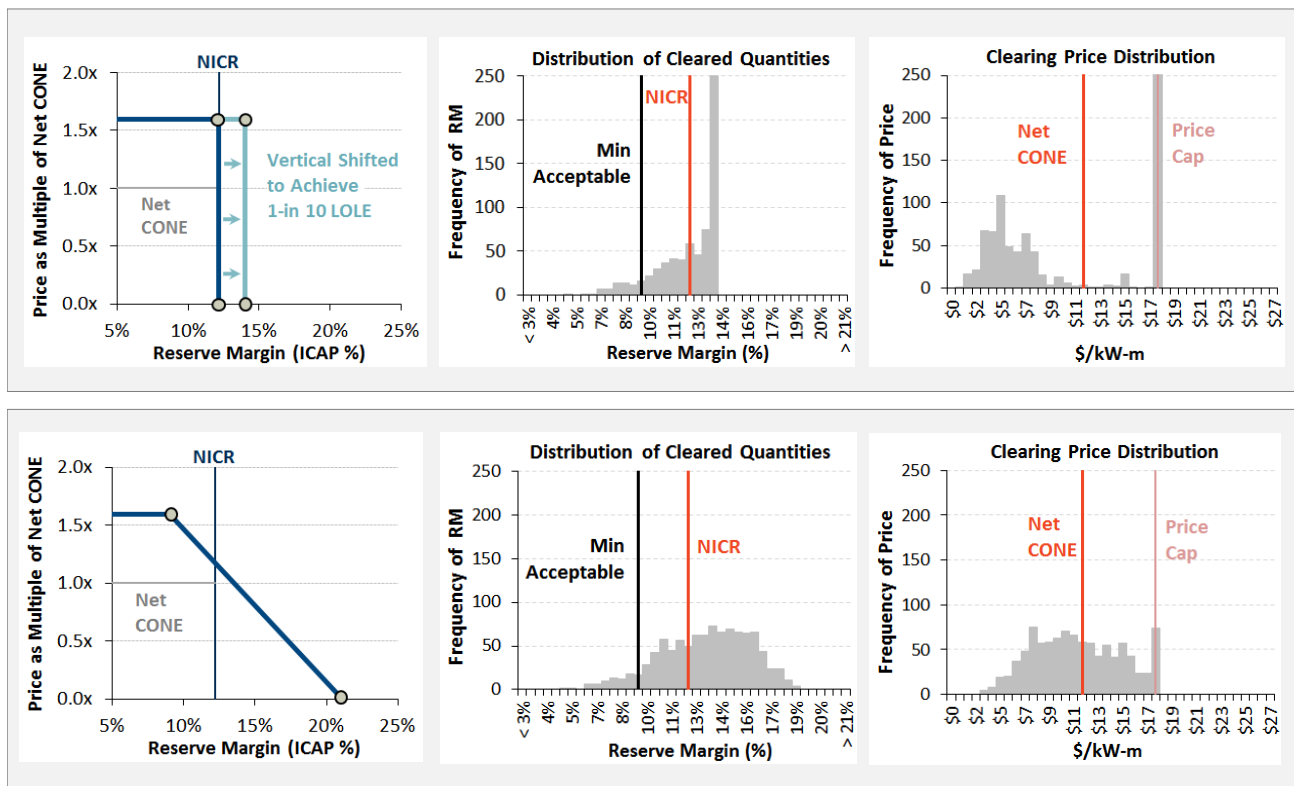


Table 4
Performance of Vertical and Proposed Demand Curves

	Price			Reliability					Price * Quantity		
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Reserve Margin	Reserve Margin St. Dev.	Frequency Below NICR	Frequency Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	(\$/kW-m)	(\$/kW-m)	(% of draws)	(events/yr)	(%)	(%)	(% of draws)	(% of draws)	(\$mil/yr)	(\$mil/yr)	(\$mil/yr)
ISO-NE Proposed	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
Vertical Curves											
Not Tuned	\$11.1	\$6.4	45.4%	0.149	11.0%	1.7%	45.3%	15.8%	\$4,339	\$1,297	\$7,040
Tuned	\$11.1	\$6.4	45.5%	0.100	12.9%	1.7%	23.7%	5.9%	\$4,418	\$1,338	\$7,159

Notes:

Average prices do not account for potential reductions in the cost of capital and Net CONE supported by more gradual demand curves. The reported Price * Quantity is the system price multiplied by the system total quantity and does not reflect zonal price differentials.

Our simulations demonstrate some of the disadvantages of a vertical demand curve. The vertical curve has a bi-modal price distribution with the majority of years showing prices substantially below Net CONE, few prices near Net CONE, and 45% of prices at the cap. This volatile, bimodal pricing is a consequence of combining a steep supply curve with a vertical demand curve, allowing a small supply reduction (or demand increase) to cause prices to spike quickly from moderate levels to the cap. Achieving prices at Net CONE on average in such a structurally volatile market requires frequent price spikes with many years at the cap, many years at low prices, and few years in between. This result is also qualitatively consistent with observations from the initial years of ISO-NE's capacity market, which resulted in: (a) six consecutive auctions with prices clearing at the floor while the market was long; (b) a seventh year when prices in NEMA-Boston spiked to the cap; and (c) the most recent eighth year when prices spiked to the cap in all zones.²⁶

Another important disadvantage of the current vertical curve is that reliability falls short of the target, with a simulated average reliability of 0.149 or 1-in-6.7 LOLE. Even though the vertical curve meets NICR in most years, the market still realizes shortages in some cases, with prices and the cap and quantities below NICR in 45.3% of all years. Combining a majority of years with reliability at 1-in-10 with a subset of years with reliability below 1-in-10 results in overall reliability levels below the target on a long-run average basis. To achieve the 1-in-10 target on average, the vertical curve would need to be right-shifted by 1.9% reserve margin percentage points. As also shown in Table 4, this right-shifted vertical curve can achieve the reliability objective but has the same poor performance in other dimensions as the vertical curve at NICR.

Finally, the current vertical curve not only shows lower reliability on average, but also results in more frequent and more severe shortage events than the proposed curve. The

²⁶ Note that the price floor prevented even lower prices during the initial six years, while administrative pricing rules prevented most suppliers from earning the clearing price at the cap in the last two years, See ISO-NE, FCM Results, posted at: http://iso-ne.com/markets/othrmkts_data/fcm/cal_results/index.html

vertical curve realizes very low quantities below the 1-in-5 minimum acceptable quantity in 15.8% of all years, compared to only 7.4% of all years with the sloped curve. This is because the sloped curve achieves higher quantities on average, which does incur a modest additional capacity procurement cost of approximately \$87 million per year on average.²⁷

In contrast, the sloped curve shows a much better-behaved profile with a smooth distribution of prices around Net CONE and only 6.4% of prices at the cap. Moving from a vertical to the proposed curve also reduces the standard deviation of prices across years from an expected \$6.4/kW-month to \$3.7/kW-month. Less volatile prices would form a more stable, less risky basis for investment while also subjecting customers to less volatility. Less sensitivity to small shifts in supply or demand would also make it less susceptible to the exercise of market power.

These results provide an illustration of the substantial reliability and volatility mitigation benefits that New England may achieve by replacing the current vertical demand curve with the proposed sloping demand curve.

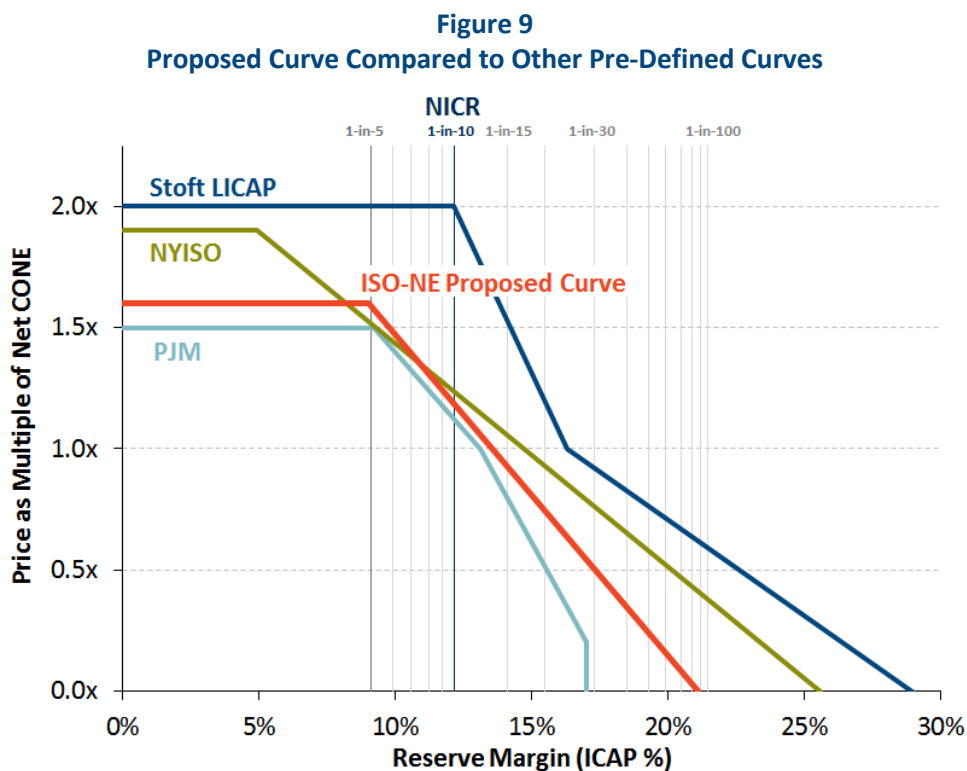
B. Performance Compared to Other Pre-Defined Curves

As a starting point for developing a demand curve for New England, we considered the performance of three previously-defined curves as shown in Figure 9: (1) PJM's Variable Resource Requirement curve; (2) NYISO's ICAP demand curve; and (3) the Stoft LICAP curve that ISO-NE proposed before the Commission in 2004.²⁸ These curves also provide a useful reference point for our proposed curve by comparing its simulated performance to others that stakeholders have considered, that other RTOs have experience implementing, and that the Commission has previously approved.

In general, ISO-NE's proposed curve has a shape, price cap, foot point, and slope within the range of these other curves. This is largely because we, ISO-NE, and stakeholders have considered many of the same factors when developing the proposed curve that were considered when designing those other curves. It is also because we incorporated lessons learned from prior analyses and historical market results in other markets when developing the proposed curve, as we explain at various points in this testimony.

²⁷ Note that this reported cost increase is a simple price-times-quantity metric at the aggregate system level that does not consider the impacts of locational clearing, or other costs and benefits associated with an increase in average installed quantities in the market. Nor does this analysis incorporate the volatility-mitigating and price-discrimination effects of ISO-NE's administrative pricing rules, as discussed in Section V.C.

²⁸ Formulas for the three curves are available from PJM's Manual 18, Section 3; NYISO Installed Capacity Manual, Section 5.5; Stoft Testimony on behalf of ISO-NE filed before the Commission August 31, 2004 in Docket ER03-563-030.



Sources and Notes:

Each curve is calculated using that market's formula as function reliability requirement, Net CONE, or Gross CONE, but using specific values as estimated for ISO-NE. PJM's curve is drawn before the subtraction of the 2.5% deduction for short-term resource procurements.

See PJM's Manual 18, Section 3; NYISO Installed Capacity Manual, Section 5.5; Stoft Testimony on behalf of ISO-NE filed before the Commission August 31, 2004 in Docket ER03-563-030.

Table 5 summarizes the performance of the proposed curve in comparison with these other pre-defined curves. Note that we simulate the performance of the other curves *as applied to the ISO-NE system*, using prices defined according to ISO-NE's Net CONE and in proportion to ISO-NE's reliability target. We would not estimate the same performance results for the NYISO and PJM curves if we applied the same simulation approach in those other systems, given their different sizes, locational structures, forward periods, and reliability drivers. We therefore stress that our conclusions about the performance of those other systems' curves apply only to our present effort to design a demand curve for ISO-NE, and would not necessarily remain true if a similar analysis were conducted in those other regions.

Acknowledging those caveats, we estimate 0.12 LOLE from the PJM curve, meaning that this curve would not achieve the 1-in-10 reliability objective in ISO-NE. This is primarily because the PJM curve has a higher frequency of low reliability events, with approximately 12% of draws below the 1-in-5 minimum acceptable level. Comparing the shape of this curve to the proposed curve and others that we have tested, we find the primary reasons for the relatively high frequency of low reliability events are its slightly left-shifted shape and lower price cap relative to what is needed to meet 1-in-10 on average.

In contrast, we estimate 0.04 and 0.08 LOLE from the Stoft LICAP and NYISO curves respectively, meaning that these curves would exceed the 1-in-10 reliability objective

in ISO-NE. Comparing the shapes of these curves to the PJM and proposed curve, we see that both the Stoft LICAP and NYISO curves are right-shifted from NICR and have higher price caps, resulting in a relatively low frequency below NICR and the 1-in-5 level. This increase in reliability comes at a cost, with average capacity procurement costs increasing by approximately \$159 million per year and \$47 million per year for the Stoft LICAP and NYISO curves, respectively, compared to the proposed curve.²⁹

In terms of price volatility, the NYISO curve performs best with the smallest standard deviation in realized prices at \$3.0/kW-month, and 0.0% of clearing prices at the price cap, and the most moderated capacity procurement costs in the top and bottom 20% of draws. The NYISO curve has the best price volatility performance because it is the flattest curve of the three, followed by the proposed curve, and then PJM's curve. The Stoft LICAP curve produces the greatest price volatility not only because it is relatively steep, but also because it has a higher price cap at $2 \times$ Net CONE.

Overall, ISO-NE's proposed curve shows good performance compared to these other pre-defined curves. However, given inherent performance tradeoffs, the proposed curve does not out-perform these other curves in all dimensions simultaneously. For example, the NYISO curve shows better performance in price volatility, but slightly higher customer costs and greater volatility in reserve margin outcomes. The Stoft LICAP curve shows fewer events below the reliability target and better overall reliability, but higher price volatility and an increase in capacity procurement costs due to the higher average reserve margin. The proposed curve balances various competing design objectives to meet the primary design objective of 1-in-10, showing good performance in all of the dimensions we measure, and poor performance in none of these dimensions.

Table 5
Performance of Proposed Curve and Other Pre-Defined Curves

	Price			Reliability					Price * Quantity		
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Reserve Margin	Reserve Margin St. Dev.	Frequency Below NICR	Frequency Below 1-in-5	Average of Average	Average of Bottom 20%	Average of Top 20%
	(\$/kW-m)	(\$/kW-m)	(% of draws)	(events/yr)	(%)	(%)	(% of draws)	(% of draws)	(\$mil/yr)	(\$mil/yr)	(\$mil/yr)
ISO-NE Proposed	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
Other Defined Curves											
Stoft	\$11.1	\$4.2	3.8%	0.043	17.5%	2.8%	3.8%	0.3%	\$4,585	\$2,812	\$7,415
PJM	\$11.1	\$3.9	11.3%	0.120	12.5%	2.5%	40.5%	11.9%	\$4,382	\$2,214	\$6,331
NYISO	\$11.1	\$3.0	0.0%	0.078	14.7%	2.9%	20.2%	4.6%	\$4,473	\$2,917	\$6,090

Notes:

Average prices do not account for potential reductions in the cost of capital and Net CONE supported by more gradual demand curves. The reported Price * Quantity is the system price multiplied by the system total quantity and does not reflect zonal price differentials.

²⁹ Note that this reported cost increase is a simple price times quantity metric at the aggregate system level that does not consider the impacts of locational clearing, or other costs and benefits associated with an increase in average installed quantities in the market.

C. Performance Compared to System-Wide Administrative Pricing Rules

One of the important drivers for implementing a sloped demand curve is to allow for the elimination of ISO-NE's system-wide administrative pricing rules from FCM, as previously articulated by the Commission, ISO-NE, and other commenters in this docket.³⁰ These rules were originally implemented to address some of the problems associated with a vertical demand curve, including price volatility, bimodal pricing, and exposure to exercise of market power, as discussed in Section V.A above. However, these rules have also introduced a number of problematic inefficiencies into the design. Eliminating the system-wide administrative rules and replacing them with a sloping demand curve can achieve the same objectives more effectively, while avoiding a number of unintended consequences.

The two administrative rules that apply on a system-wide basis, referred to as the Inadequate Supply and Insufficient Competition rules, can be triggered by certain short-supply conditions in an FCA.³¹ When triggered, the rules will override auction clearing prices with pre-determined administrative prices for existing resources. These rules are intended to protect customers against sudden price spikes caused by bi-modal pricing outcomes under the vertical curve and to mitigate against the potential exercise of market power.

The most efficient auction clearing results and resource investments are facilitated by a level playing field where all resource types compete to receive the same payments for providing the same product. A characteristic of the system-wide administrative pricing rules is price discrimination, with new and existing units paid different prices for providing the same capacity product. This means that the Insufficient Competition and Inadequate Supply Rules could potentially provide uneconomically low incentives for existing resources to invest in cost-effective retrofits, life-extensions, maintenance, and demand response re-contracting. In some cases, reinvestments in existing resources can be substantially more cost-effective than developing a new resource. The expectation of systematic under-payment to existing resources also means that new resources must inflate their offer levels to ensure higher prices upon entry, if they are to recover investment costs over the asset life including the years when they will be classified as existing supply. By replacing the administrative pricing rules with a downward-sloping demand curve, these problematic price discrimination effects will be resolved.³²

³⁰ For additional discussion of this issue, see FERC Orders from January 24, 2014 in Dockets EL14-7-000 and ER14-463-000. As explained in its concurrent filing letter, ISO-NE proposes to eliminate the system-wide application of these rules upon implementation of the system-wide demand curve. The zonal application of these rules will be addressed with stakeholders when the ISO addresses implementation of zonal demand curves. For the current tariff language describing these rules, see ISO-NE Market Rule 1, Sections III.13.2.8.1, III.13.2.7.9, and III.A.21.1.

³¹ A third administrative rule, the Capacity Carry Forward rule, applies only to import-constrained zones that are affected by excess procurement from lumpy unit entry in the immediately prior auction. This rule is intended to protect existing suppliers against downward price volatility caused by lumpy entry.

³² We note that some price discrimination will continue under ISO-NE's provisions allowing for Capacity Commitment Period Election for new resources.

In addition, replacing the system-wide administrative rules with a sloping demand curve will improve efficiency by producing clearing prices and incentives that are more reflective of market conditions. While the sloped demand curve will dampen large price movements caused by sudden shocks to supply and demand, it does not completely eliminate these price signals. Under a demand curve, prices will be more stable than with a vertical curve, but will still be set by the intersection of supply and demand and therefore change with the underlying market fundamentals. By comparison, the current administrative rules set payout rates at specific pre-defined levels based on binary trigger rules. Therefore, the administrative rules could produce counter-intuitive incentives that do not necessarily track system needs. A downward-sloping demand curve will support more graduated price movements over time, for example supporting more steadily-increasing prices as the system tightens, and thereby signal the appropriate timing and relative value of incremental supply investments.

D. Impact of Varying the Price Cap and Minimum Quantity

Two of the most important factors driving the overall performance of a capacity demand curve are the price and highest quantity at the cap, proposed at $1.6 \times$ Net CONE and 1-in-5 respectively. The placement of the price cap has important implications for realized price volatility, reliability, and frequency of low reliability events. Additionally, determining this point also narrows the options available for defining the rest of the demand curve, if the resulting curve is required to meet a 1-in-10 reliability target on average.

To illustrate the performance impacts of these parameters, we adjust them over a range of $1.4 \times$ to $2.0 \times$ Net CONE for the price and 1-in-4 to 1-in-10 for the highest quantity priced at the cap. However, because changing any one dimension of the curve affects the realized reliability performance, we then “tune” each curve to maintain 1-in-10 by adjusting the quantity at the foot. This allows us to compare the performance of a number of curves that all meet the primary design objective, while evaluating tradeoffs in other dimensions. The resulting curves are shown in Figure 10, with performance metrics under each curve summarized in Table 6.

Figure 10
Straight-Line Curves with Varying Prices (Left) and Quantities (Right) at the Cap
 All Curves Tuned to Meet the 1-in-10 Reliability Objective

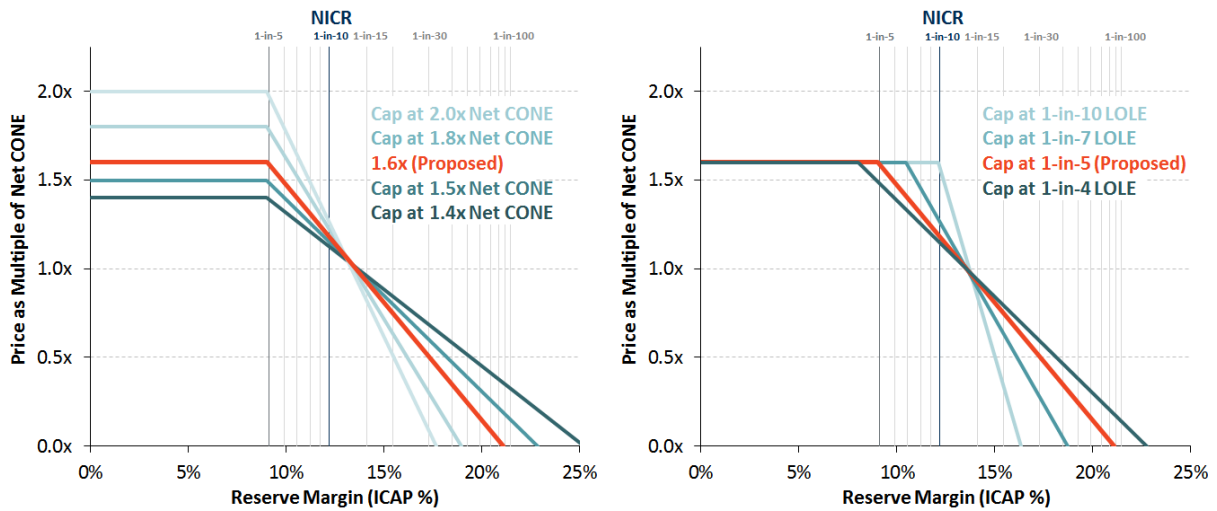


Table 6
Performance of Curves with Varying Prices and Quantities at the Cap
 All Curves Tuned to Meet the 1-in-10 Reliability Objective

	Price			Reliability					Price * Quantity		
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Reserve Margin	Reserve Margin St. Dev.	Frequency Below NICR	Frequency Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	(\$/kW-m)	(\$/kW-m)	(% of draws)	(events/yr)	(%)	(%)	(% of draws)	(% of draws)	(\$mil/yr)	(\$mil/yr)	(\$mil/yr)
ISO-NE Proposed	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
Price Cap											
1.4x Net CONE	\$11.1	\$2.6	6.4%	0.100	13.6%	2.9%	31.4%	7.8%	\$4,422	\$2,996	\$5,802
1.5x Net CONE	\$11.1	\$3.2	6.4%	0.100	13.5%	2.8%	31.4%	7.5%	\$4,428	\$2,728	\$6,134
1.6x (Proposed)	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
1.8x Net CONE	\$11.1	\$4.7	6.4%	0.100	13.4%	2.5%	31.0%	7.2%	\$4,423	\$2,123	\$7,134
2.0x Net CONE	\$11.1	\$5.5	5.8%	0.100	13.3%	2.3%	30.5%	6.9%	\$4,412	\$1,846	\$7,759
Quantity at the Cap											
1-in-4 LOLE	\$11.1	\$3.3	3.7%	0.100	13.5%	2.8%	31.7%	7.8%	\$4,425	\$2,710	\$6,215
1-in-5 (Proposed)	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
1-in-7 LOLE	\$11.1	\$4.5	13.7%	0.100	13.4%	2.5%	31.2%	7.2%	\$4,421	\$2,112	\$6,863
1-in-10 LOLE	\$11.1	\$5.4	27.2%	0.100	13.2%	2.2%	27.2%	6.6%	\$4,407	\$1,631	\$7,054

Notes:

Average prices do not account for potential reductions in the cost of capital and Net CONE supported by more gradual demand curves. The reported Price * Quantity is the system price multiplied by the system total quantity and does not reflect zonal price differentials.

Increasing or decreasing the price cap introduces a number of important performance tradeoffs that must be considered. In general, the price cap must be high enough to: (a) support long-run average prices at Net CONE; (b) exceed the true Net CONE that developers need to enter the market, including a substantial margin for administrative error in estimating Net CONE; (c) reflect the very high value of incremental capacity during shortage years when capacity is scarce; (d) prevent an excessive number of years at the price cap, which indicates that the curve can only produce prices high enough on average by generating

more frequent low reliability events; (e) prevent the need for a very right-shifted curve in order to meet 1-in-10 on average; and (f) prevent problems associated with a very flat curve that over-dampens price signals reflective of year-to-year changes in fundamentals. Of these issues, we place the greatest emphasis on ensuring that the cap exceeds true developer Net CONE by a substantial margin for error. Under any curve, underestimating Net CONE will degrade reliability, but the risks are greatest when combined with a low price, as discussed further in Section VI.B below.

There are also important reasons to limit the price cap to a moderate level, including to: (a) mitigate against extreme price volatility; (b) prevent payments that far exceed the value of capacity during shortage years; (c) acknowledge the possibility that additional supply may become available in later auctions at a lower (but still high) price; and (d) limit the incentive and impacts of exercising market power. Among these concerns, stakeholders placed the most emphasis on mitigating price volatility and the ability to exercise market power.

These considerations suggest that a price cap in the range of $1.5 \times$ to $2 \times$ Net CONE is most desirable, and the simulation results in Table 6 show generally good performance for all curves over this range. The primary performance impact across this range is the substantial increase in price volatility from a standard deviation of \$3.2/kW-month to \$5.5/kW-month corresponding to price caps of $1.5 \times$ to $2 \times$ Net CONE respectively.

Ultimately, ISO-NE and stakeholders selected a cap of $1.6 \times$ Net CONE that reflects an appropriate balance of the above objectives. The selected cap is in the lower end of the well-performing range primarily because: (1) the cap will be similar to those in PJM and NYISO at $1.5 \times$ Net CONE and $1.5 \times$ gross CONE respectively; (2) the price cap for the first implementation year in FCA9 will be a moderate but not extreme increase in absolute terms; and (3) many stakeholders placed a strong emphasis on price volatility and the market power mitigation benefits of having a moderate price cap. Yet avoiding the very lowest end of the well-performing range mitigates against the reliability risks posed by potentially underestimating Net CONE.

The quantity where prices reach the cap is also an important driver of performance. A lower quantity at the cap corresponds with a flatter curve, lower price volatility, and therefore fewer events at the price cap. For example, increasing the quantity at the cap point from 1-in-5 to 1-in-7 more than doubles the frequency of price cap events from 6% to 14% of outcomes, which is on the high end of the range that we could consider well-performing.³³ Because these substantial increases in price volatility and price cap events are not balanced by substantial improvements in other dimensions, we find that the lower proposed quantity of 1-in-5 is preferable.

Continuing to reduce the quantity at the cap would further improve price volatility and related metrics, but it would introduce other substantial concerns. Most importantly, 1-

³³ Note that other curves with different caps and overall shapes could be developed that would be well-performing with a cap quantity of 1-in-7.

in-5 is the reliability level that ISO-NE must achieve before administrative intervention becomes more likely. Setting the cap quantity equal or greater to 1-in-5 will ensure that ISO-NE exhausts every possible opportunity for market-based capacity procurement before engaging in out-of-market backstop procurements that could compromise economic efficiency and could undermine market signals, depending on how they are implemented.

Overall, we believe that the proposed curve with a cap at $1.6 \times$ Net CONE and a quantity of 1-in-5 is likely to be well-performing. Further adjustments to the price or quantity at the cap may result in modest improvements in some dimensions but would be unlikely to materially improve in multiple dimensions simultaneously. Perhaps most importantly, the placement and definition of the cap will protect against some of the most problematic potential reliability consequences (with a low or left-shifted cap) as well as extreme price volatility or exercise of market power (with a high cap or steep curve).

E. Impact of Varying Demand Curve Slope

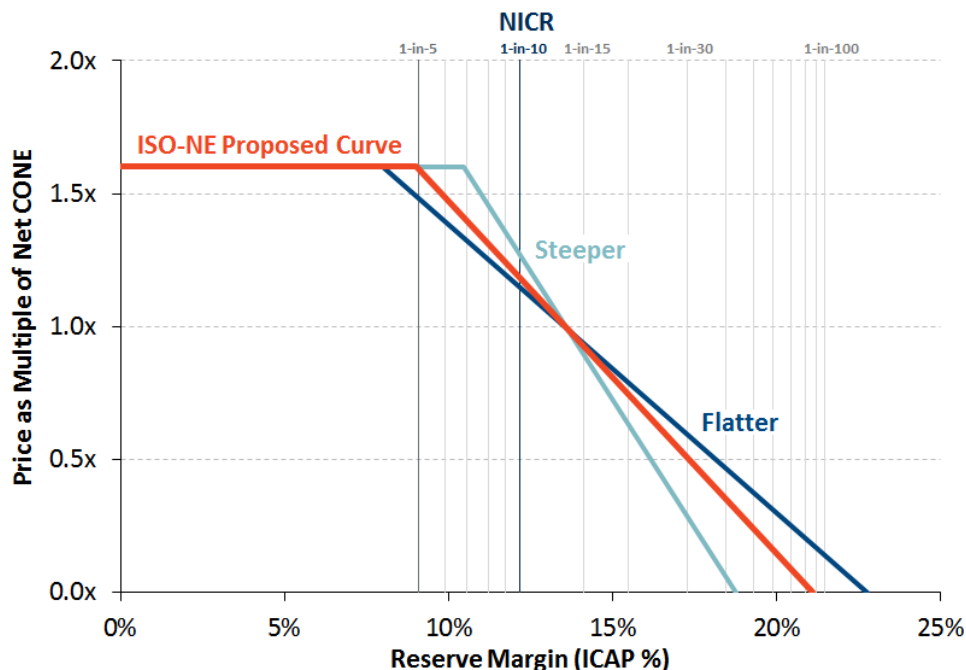
The slope of the demand curve is also an important determinant of performance, although there is a substantial range of slopes that could be considered well-performing with a different balance of performance tradeoffs. We illustrate these tradeoffs by comparing the proposed curve to flatter and steeper curves that also meet the 1-in-10 reliability objective, as shown in Figure 11.³⁴ Figure 12 compares the detailed price and quantity results under each curve, while Table 7 summarizes each curve's performance under additional dimensions.

The incremental tradeoffs among these three curves are similar in both direction and magnitude to those that we find among many steeper and flatter curves. Most fundamentally, these tradeoffs reflect the balance between price uncertainty and quantity uncertainty

Flatter curves provide more price stability and better protection against the exercise of market power. This improvement in price stability is illustrated in Figure 11 as a better-behaved and smoother distribution of prices near the average expected value compared to the proposed and steeper curves. However, flatter curves also dampen price signals from year-to-year changes in market conditions, increase quantity uncertainty in any one year, increase the quantity and reliability impacts of errors in administrative Net CONE, increase the frequency of events below 1-in-5, and therefore require a slight right-shift in the entire curve in order to maintain the 1-in-10 reliability objective on average.

³⁴ Note that the flatter and steeper curves are identical to the 1-in-4 and 1-in-7 cap quantity curves presented in Section V.D above, although we use these curves here to discuss different aspects of performance.

Figure 11
Proposed Curve Compared to Flatter and Steeper Curves
 All Curves Tuned to Meet the 1-in-10 Reliability Objective



Steeper curves have the opposite tradeoffs, with greater quantity certainty achieved at the expense of greater price volatility. Among the three curves presented below, the steeper curve shows the highest price volatility, highest frequency at the price cap, and the widest distribution of prices. For example, the steepest curve shows the highest quintile of capacity procurement cost outcomes at 3.2 times the lowest quintile, compared to 2.3 times in the flattest curve which substantially moderates these price extremes. The steeper curve also shows a directional reduction in total capacity procurement costs, but the magnitude is negligible. More importantly in terms of quantity uncertainty, the steeper curve would be less affected by administrative errors in Net CONE.

The proposed curve has a moderate slope that is within the range of well-performing curves that we have identified and evaluated. It achieves substantial price volatility and market power mitigation benefits compared to the vertical curve or steeper curves, but is still steep enough to prevent excessive reliability risks from potential underestimation of Net CONE. Moderate changes to the slope would provide a different balance among these objectives, and would likely continue to be well-performing unless the slope were to be made much flatter or steeper.

Figure 12
Simulated Price and Quantity Outcomes with Steeper and Flatter Curves
 All Curves Tuned to Meet the 1-in-10 Reliability Objective

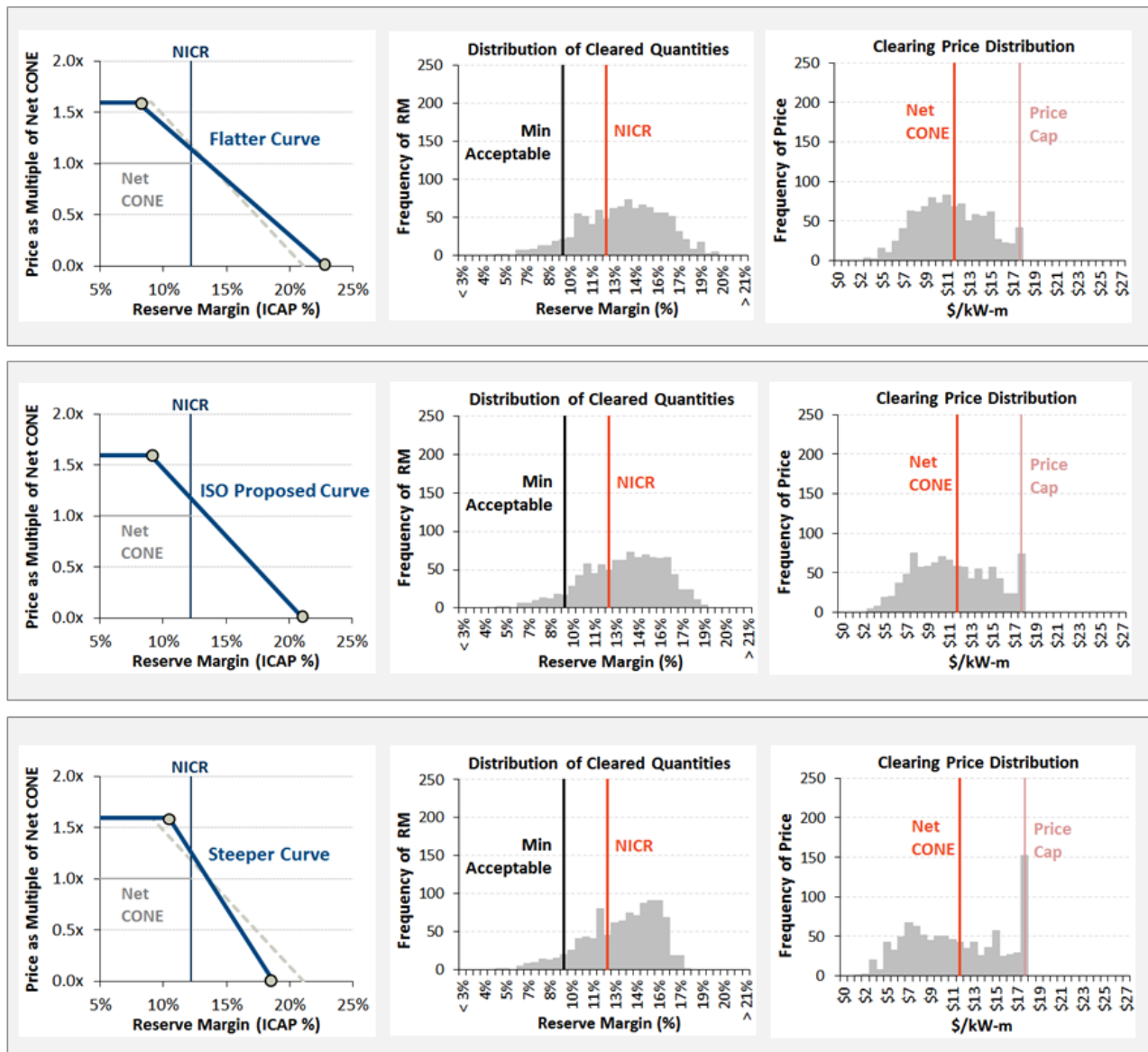


Table 7
Performance of Curves with Varying Demand Curve Slopes
 All Curves Tuned to Meet the 1-in-10 Reliability Objective

	Price			Reliability					Price * Quantity		
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Reserve Margin	Reserve Margin St. Dev.	Frequency Below NICR	Frequency Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	(\$/kW-m)	(\$/kW-m)	(% of draws)	(events/yr)	(%)	(%)	(% of draws)	(% of draws)	(\$mil/yr)	(\$mil/yr)	(\$mil/yr)
ISO-NE Proposed	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
Varied Slopes											
Flatter Curve	\$11.1	\$3.3	3.7%	0.100	13.5%	2.8%	31.7%	7.8%	\$4,425	\$2,710	\$6,215
Steeper Curve	\$11.1	\$4.5	13.7%	0.100	13.4%	2.5%	31.2%	7.2%	\$4,421	\$2,112	\$6,863

Notes:

Average prices do not account for potential reductions in the cost of capital and Net CONE supported by more gradual demand curves. The reported Price x Quantity is the system price multiplied by the system total quantity and does not reflect zonal price differentials.

F. Impact of Varying the Demand Curve Shape

In our work with ISO-NE and stakeholders we evaluated a number of differently demand curve shapes. We describe here the theoretical and simulated performance benefits of different demand curve shapes, focusing on straight-line, convex kinked, and convex multi-point options. As in other sections of this testimony, we illustrate these impacts by comparing options that have the varying shapes shown in Figure 13, but that have the same cap and similar slopes in all cases. We present simulated performance results in Table 8. In general, we find a number of theoretical merits to a convex shape, but find that the shape has a relatively modest simulated performance impact in most dimensions (and in some dimensions, the simulated performance and susceptibility to market power abuse is worse than for the proposed curve).

Figure 13
Proposed Curve Compared to Convex Kinked and Convex Multi-Point Curves

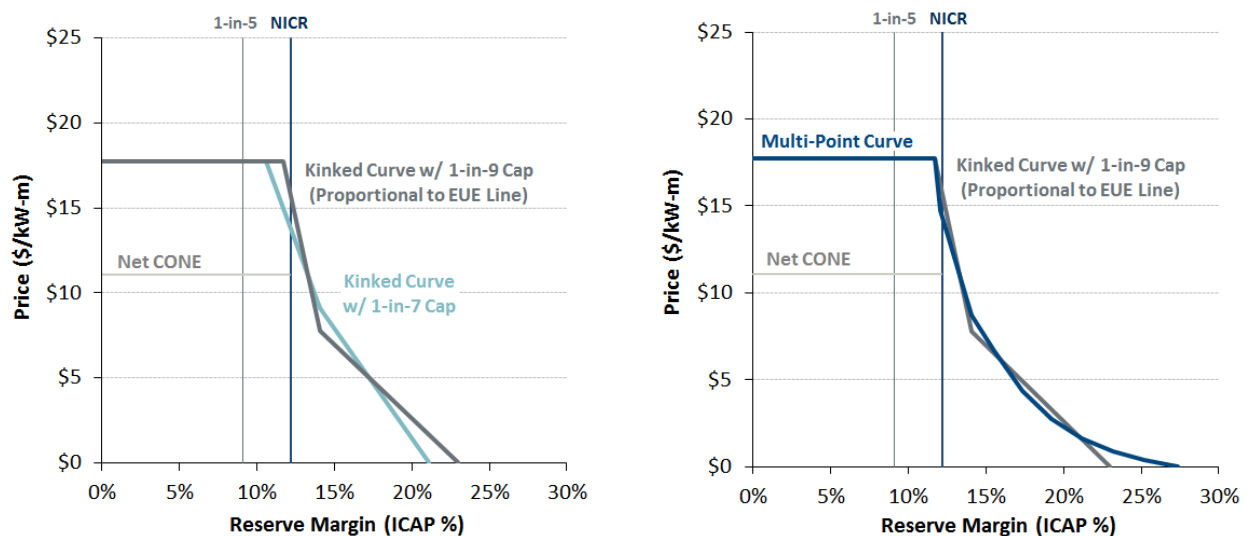


Table 8
Performance of Curves with Varying Shapes and Convexity

	Price			Reliability					Price * Quantity		
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Reserve Margin	Reserve Margin St. Dev.	Frequency Below NICR	Frequency Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	(\$/kW-m)	(\$/kW-m)	(% of draws)	(events/yr)	(%)	(%)	(% of draws)	(% of draws)	(\$mil/yr)	(\$mil/yr)	(\$mil/yr)
ISO-NE Proposed	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
Kinked Curves											
Cap at 1-in-7	\$11.1	\$4.3	15.0%	0.100	13.4%	2.6%	31.4%	7.4%	\$4,413	\$2,326	\$6,888
Cap at 1-in-9	\$11.1	\$4.9	23.8%	0.100	13.3%	2.5%	28.8%	7.2%	\$4,404	\$2,158	\$7,023
Multi-Point (Cap at 1-in-9)	\$11.1	\$4.7	23.7%	0.100	13.4%	2.5%	30.7%	7.2%	\$4,430	\$2,227	\$7,018

Notes:

Average prices do not account for potential reductions in the cost of capital and Net CONE supported by more gradual demand curves. The reported Price * Quantity is the system price multiplied by the system total quantity and does not reflect zonal price differentials.

The straight-line curve is the simplest and easiest to implement, resulting in greater transparency and fewer implementation costs. The straight-line curve also has the lowest price volatility compared to other curves with the same cap and a similar slope. A theoretical disadvantage of the straight-line curve is that the single slope of the curve means that it expresses a marginal value of capacity that does not change as the reserve margin exceeds the requirement. For example, an additional 100 MW of supply when the system is long causes the same price change as 100 MW of supply when the system is short of the target. Another disadvantage of the straight-line curve is that realized quantity and reliability outcomes are more susceptible to errors in administrative Net CONE than a convex curve would be.

Convex shaped curves, whether simple kinked or multi-point versions have a number of theoretical advantages. A convex shape is more reflective of the incremental reliability and economic value of capacity, with a steeper slope at low reserve margins and a gradual fall-off at higher reserve margins. For example, we illustrate kinked and multi-point curves in Figure 13 that are approximately proportional to the marginal avoided expected unserved energy (EUE) as calculated by ISO-NE staff. A convex shape would also tend to produce a price distribution more consistent with other commodity market prices, with a fatter tail on the high-price side (although when combined with a modest or low price cap, a convex curve tends to have the undesirable consequence of increasing the frequency of price-cap events). Perhaps most importantly, a convex shape is more robust to Net CONE estimation errors, with underestimation leading to smaller shortfalls than for the proposed curve, as discussed in Section VI.B.

Disadvantages of the convex curve include its greater complexity, greater susceptibility to the exercise of market power in the high price region, and greater price volatility. The latter two points are the most important disadvantages in our context, in particular the increase in price volatility that is greater than we anticipated prior to conducting this simulation analysis. This increase in volatility is driven by the steep shape of the supply curve in the high-price region above Net CONE. The convex curve combines that steep portion of the supply curve with a steep portion of the demand curve, resulting in

relatively volatile prices under short-supply conditions. The straight-line curve moderates that impact.

Comparing performance metrics from Table 8 shows that a modest kink increases price volatility from a standard deviation of \$3.7/kW-month to \$4.3/kW-month, and more importantly almost triples events at the cap from 6% to an undesirably high 15%. Because of this tendency to produce higher price volatility and more price-cap events, we found that convex curves tend to perform better when combined with either a higher price cap or a right-shifted foot.

Finally, we compare the performance of a simpler kinked convex curve to a multi-point curve with a very similar shape as shown in the right-hand chart in Figure 13. The advantages of convex curves are theoretically amplified by extending the concept to a more continuous shape, for example by adding more points to better reflect proportionality to marginal reliability value. However, the magnitude of these incremental benefits is very small given the relatively close approximation of the linearized version of the same overall shape. This conclusion is supported by the results of Table 8, which shows nearly identical performance between the kinked and multi-point variations of the same curve except for a minor improvement in price volatility. We believe that these small performance improvements do not justify the substantially greater administrative complexity and stakeholder work that would be involved in defining such a multi-point curve in this context.

Stakeholders and ISO-NE considered these advantages and disadvantages before deciding on the simplest straight-line option. While the theoretical merits of a convex-shaped curve could justify adopting such a shape in some contexts, stakeholders placed more emphasis on the price volatility and other benefits of a straight-line curve for New England. We believe based on our simulation results that the straight-line curve is well-performing according to our stipulated design objectives. In addition, we find that the shape of the curve (straight vs. kinked) is not as important a determinant of performance as the price cap and slope. The proposed curve has a reasonable price cap and slope that should support good performance.

G. Summary of Performance Compared to Alternative Curves

Thus far in our testimony, we have compared the performance of the proposed demand curve to other pre-defined curves as well as a number of similarly-shaped curves to illustrate the impacts of adjusting the cap, slope, or shape. However, in the process of developing the proposed curve, we have also evaluated a much larger number of potential curves with very different characteristics. To provide a more comprehensive snapshot of this analysis, we also report our estimated performance for a subset of the curves proposed in the NEPOOL stakeholder process as shown in Figure 14. The chart shows that compared to the ISO-NE proposed curve, these alternative proposals are left-shifted, right-shifted, or reflect a substantially different shape.

Figure 14
Proposed Curve Compared to a Selection of Stakeholder-Proposed Curves

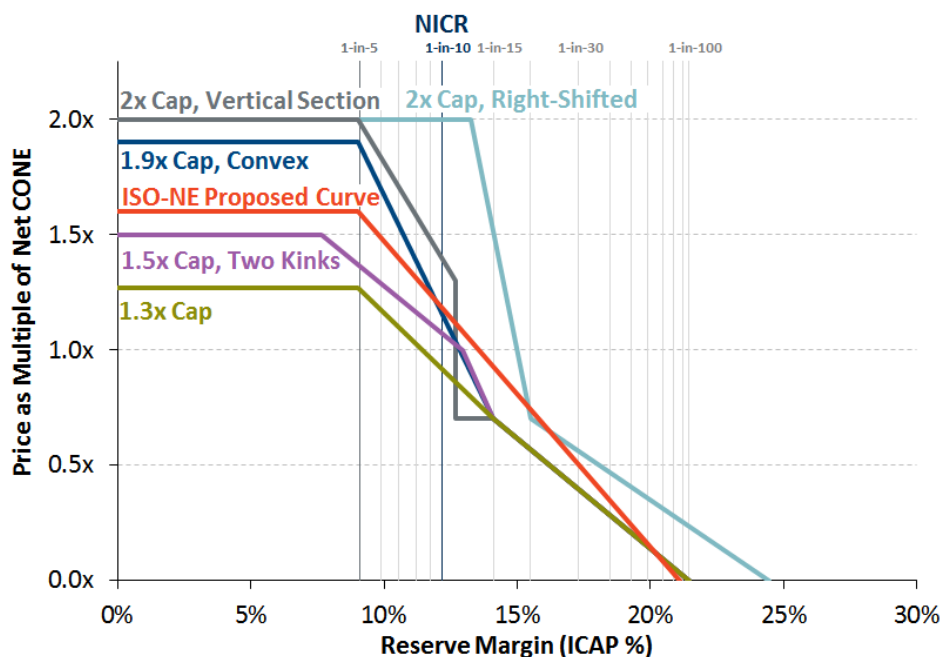


Table 9 compares the performance of these alternative curves to the proposed curve, as well as to a number of others that we presented earlier. These curves provide a more comprehensive illustration of the concepts that we have incorporated into the selection of the proposed curve that we have discussed above. Specifically, we selected a curve that: (1) is calibrated to meet 1-in-10 primary design objective; and (2) shows good or excellent performance in all of the dimensions that we measured (or put another way, poor performance in none of these dimensions). Within these constraints we found a number of well-performing curves, or curves that could meet the objectives with minor adjustments. The proposed curve is among these well-performing options, with excellent performance in dimensions related to price volatility and good performance in other dimensions.

Table 9
Performance Summary of Proposed and Alternative Curves

	Price			Reliability					Price * Quantity		
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Reserve Margin	Reserve Margin St. Dev.	Frequency Below NICR	Frequency Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	(\$/kW-m)	(\$/kW-m)	(% of draws)	(events/yr)	(%)	(%)	(% of draws)	(% of draws)	(\$mil/yr)	(\$mil/yr)	(\$mil/yr)
ISO-NE Proposed	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
Other Pre-Defined Curves											
Vertical (Not Tuned)	\$11.1	\$6.4	45.4%	0.149	11.0%	1.7%	45.3%	15.8%	\$4,339	\$1,297	\$7,040
Stoft	\$11.1	\$4.2	3.8%	0.043	17.5%	2.8%	3.8%	0.3%	\$4,585	\$2,812	\$7,415
PJM	\$11.1	\$3.9	11.3%	0.120	12.5%	2.5%	40.5%	11.9%	\$4,382	\$2,214	\$6,331
NYISO	\$11.1	\$3.0	0.0%	0.078	14.7%	2.9%	20.2%	4.6%	\$4,473	\$2,917	\$6,090
Curves Tuned to 1-in-10											
Vertical	\$11.1	\$6.4	45.5%	0.100	12.9%	1.7%	23.7%	5.9%	\$4,418	\$1,338	\$7,159
Price Cap at 1.4x Net CONE	\$11.1	\$2.6	6.4%	0.100	13.6%	2.9%	31.4%	7.8%	\$4,422	\$2,996	\$5,802
Price Cap at 1.5x Net CONE	\$11.1	\$3.2	6.4%	0.100	13.5%	2.8%	31.4%	7.5%	\$4,428	\$2,728	\$6,134
Price Cap at 1.8x Net CONE	\$11.1	\$4.7	6.4%	0.100	13.4%	2.5%	31.0%	7.2%	\$4,423	\$2,123	\$7,134
Price Cap at 2.0x Net CONE	\$11.1	\$5.5	5.8%	0.100	13.3%	2.3%	30.5%	6.9%	\$4,412	\$1,846	\$7,759
Cap Quantity at 1-in-4 LOLE	\$11.1	\$3.3	3.7%	0.100	13.5%	2.8%	31.7%	7.8%	\$4,425	\$2,710	\$6,215
Cap Quantity at 1-in-7 LOLE	\$11.1	\$4.5	13.7%	0.100	13.4%	2.5%	31.2%	7.2%	\$4,421	\$2,112	\$6,863
Cap Quantity at 1-in-10 LOLE	\$11.1	\$5.4	27.2%	0.100	13.2%	2.2%	27.2%	6.6%	\$4,407	\$1,631	\$7,054
Kinked Curve, Cap at 1-in-7 LOLE	\$11.1	\$4.3	15.0%	0.100	13.4%	2.6%	31.4%	7.4%	\$4,413	\$2,326	\$6,888
Kinked Curve, Cap at 1-in-9 LOLE	\$11.1	\$4.9	23.8%	0.100	13.3%	2.5%	28.8%	7.2%	\$4,404	\$2,158	\$7,023
Multi-Point, Cap at 1-in-9 LOLE	\$11.1	\$4.7	23.7%	0.100	13.4%	2.5%	30.7%	7.2%	\$4,430	\$2,227	\$7,018
Stakeholder Proposed Curves											
1.5x Cap, Two Kinks	\$11.1	\$3.5	6.3%	0.134	12.1%	2.7%	46.2%	16.1%	\$4,382	\$2,464	\$6,093
2x Cap, Vertical Section	\$11.1	\$5.8	6.4%	0.100	13.3%	2.5%	29.0%	6.9%	\$4,394	\$2,178	\$7,974
1.6x Cap	\$11.1	\$3.6	5.6%	0.096	13.6%	2.7%	30.4%	6.7%	\$4,428	\$2,524	\$6,441
1.5x Cap, Tuned	\$11.1	\$3.2	6.4%	0.100	13.5%	2.8%	32.1%	7.8%	\$4,419	\$2,704	\$6,140
1.3x Cap	\$11.1	\$2.7	25.6%	0.181	11.0%	2.9%	62.8%	29.2%	\$4,324	\$2,788	\$5,434
1.3x Cap Tuned	\$11.1	\$1.8	7.3%	0.100	13.6%	3.1%	31.8%	8.4%	\$4,448	\$3,486	\$5,332
2x Cap, Right Shifted	\$11.1	\$6.4	16.8%	0.060	15.5%	2.4%	9.2%	1.4%	\$4,495	\$2,111	\$8,821
1.9x Cap, Convex	\$11.1	\$5.0	7.3%	0.106	13.1%	2.5%	33.3%	8.9%	\$4,400	\$2,239	\$7,526

Notes:

Average prices do not account for potential reductions in the cost of capital and Net CONE supported by more gradual demand curves. The reported Price * Quantity is the system price multiplied by the system total quantity and does not reflect zonal price differentials.

VI. SENSITIVITY TO SYSTEM CONDITIONS AND MODELING UNCERTAINTIES

Our evaluation of the proposed curve presented in Section V is based on the specific set of system conditions and modeling assumptions described in Section IV. However, the curve will be implemented in the real world, where conditions are uncertain and will evolve over time. It is important to know that the curve will continue to perform well, sustainably supporting a well-functioning market that efficiently meets reliability objectives over the long-term.

To test how well the curve would perform as system conditions change or if modeling assumptions are wrong, we conducted several sensitivity analyses. We varied the magnitude of Net CONE, Net CONE estimation error, and the size of supply and demand shocks. Finally, we tested how the demand curve's performance could be affected by ISO-NE's Pay for Performance (PFP) proposal.

A. Sensitivity to System Net CONE

The prices on the demand curve are indexed to Net CONE, so the curve will be adjusted as Net CONE estimates change over time. For this reason, if energy prices decrease and the energy market provides a smaller proportion of the incentives necessary to invest, then the administrative Net CONE and capacity demand curve will increase even if CONE stays the same. Similarly, when energy prices increase, the demand curve will decrease providing approximately the same investment incentives overall.

However, the curve shape was fine-tuned based on the current value of Net CONE, so it is possible that future adjusted curves will not meet resource adequacy objectives exactly. To test the robustness of the curve to changes in Net CONE, we present simulation analyses with Net CONE varying from 40% to 120% of the base value. We test more extreme decreases than increases because the currently low E&AS offset has more upside than downside. The current E&AS is \$3/kW-month, and dropping by even half of that is unlikely. Note that these sensitivities reflect changes in Net CONE under the assumption of no estimation error; sensitivities to estimation error are presented in the following section.

We find that the curve continues to meet resource adequacy targets almost exactly, for modest changes of 20%, as shown in Figure 15 and Table 10. For much larger decreases in Net CONE, reliability exceeds the objective more substantially. A 60% decrease reduces LOLE to 0.087 events per year, before considering the price cap minimum that would take effect when E&AS is large. The intuition behind the higher reliability is that low Net CONE drops the demand curve to a lower price range where the supply curve is more elastic. Supply elasticity mitigates the reliability effects of supply and demand shocks.

However, if the 60% decrease is due to a large E&AS offset and the $1 \times$ CONE price cap minimum takes effect, the curve drops only modestly despite Net CONE being quite low. The curve procures almost 4% more capacity and reduces LOLE to 0.04 events per year. This may seem excessive if Net CONE truly is so low, but the cap minimum is necessary to

protect against Net CONE estimation error precipitously compromising reliability, see the following Section VI.B.

To address a potential future with very low Net CONE, ISO-NE could consider recalibrating the demand curve parameters to achieve and not exceed reliability targets. However, re-calibration would be unnecessary if Net CONE remains within the substantial uncertainty band around the base value of \$11.08/kW-month on which the proposed curve was calibrated.

Figure 15
Proposed Curve with +/-20% Net CONE (Left) and Low Net CONE w/ Cap at Minimum (Right)

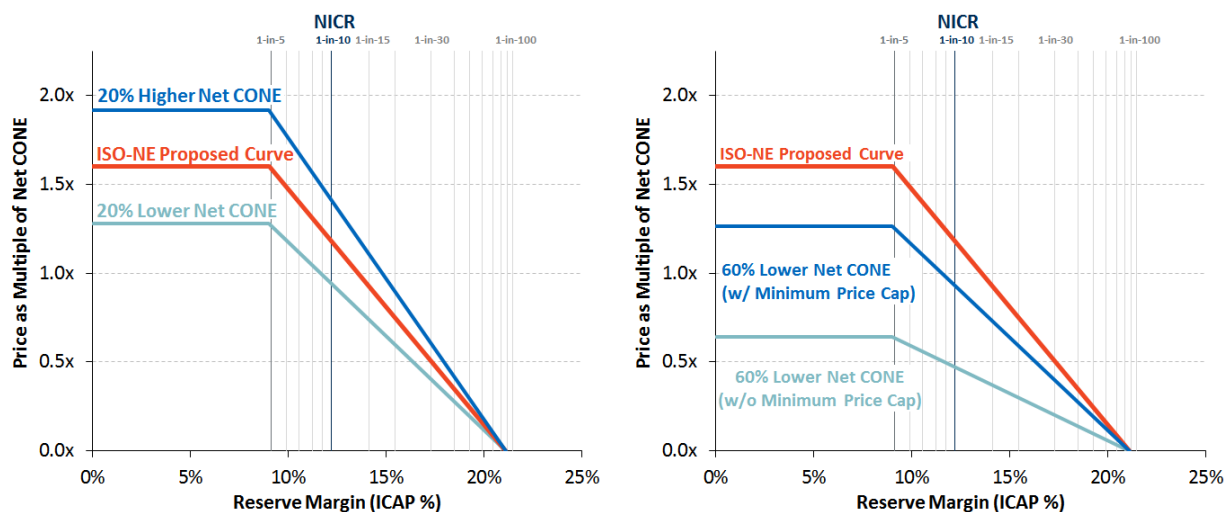


Table 10
Performance Summary of Proposed Curve under Varying System Net CONE
 Assuming the Administrative Net CONE is Accurate in All Cases

	Price			Reliability					Price * Quantity		
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Reserve Margin	Reserve Margin St. Dev.	Frequency Below NISR	Frequency Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	(\$/kW-m)	(\$/kW-m)	(% of draws)	(events/yr)	(%)	(%)	(% of draws)	(% of draws)	(\$mil/yr)	(\$mil/yr)	(\$mil/yr)
ISO-NE Proposed	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
System Net CONE											
120% of Proposed	\$13.3	\$4.6	7.0%	0.101	13.4%	2.8%	30.4%	8.9%	\$5,312	\$2,829	\$7,834
80% of Proposed	\$8.9	\$2.8	6.6%	0.099	13.5%	2.6%	29.4%	7.6%	\$3,543	\$2,135	\$5,157
40% (Cap at Gross CONE)	\$4.4	\$1.7	0.0%	0.037	17.3%	1.4%	0.4%	0.0%	\$1,828	\$1,046	\$2,891
40% (No Gross CONE Min.)	\$4.4	\$1.1	1.8%	0.087	13.6%	1.9%	19.4%	2.6%	\$1,768	\$1,228	\$2,401

Notes:

Average prices do not account for potential reductions in the cost of capital and Net CONE supported by more gradual demand curves. The reported Price * Quantity is the system price multiplied by the system total quantity and does not reflect zonal price differentials.

B. Sensitivity to Administrative Errors in Net CONE

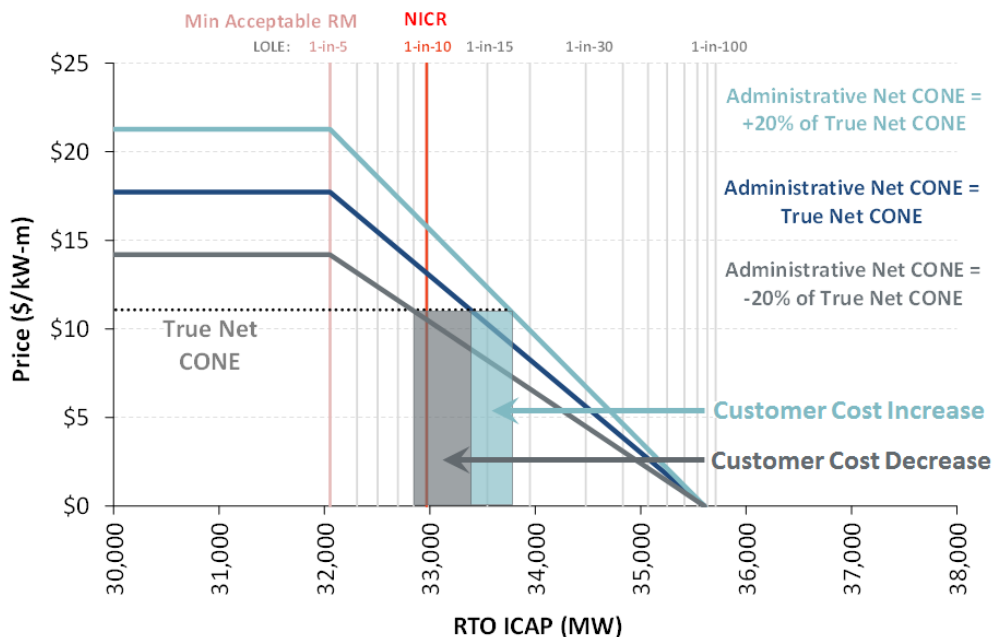
The analyses we have presented up to this point have assumed that the administrative estimate of Net CONE accurately represents the true Net CONE that developers need to earn in order to enter. However, estimation error is inevitable even in a careful analysis due to uncertainties in every component of Net CONE estimate; for example: (a) the identification of an appropriate reference technology; (b) estimation of the capital and fixed operations and maintenance (O&M) costs; (c) translation of those costs into an appropriately leveled value consistent with developers' cost of capital, long-term views about the market, and assumed economic life; and (d) estimation of E&AS margins on a 3-year forward basis.

If the administrative estimate of Net CONE understates true Net CONE, the demand curve would be lower than needed to meet the reliability objectives. Supply would still enter and set prices at the true Net CONE, but the cleared quantity and reliability would be below target. Conversely, overstated Net CONE would attract excess supply as suppliers continued entering until average prices equal the true Net CONE. Customers would not have to pay significantly higher prices, but they would have to buy a greater quantity that has diminishing value.

We test the robustness of the demand curve's performance to Net CONE estimation errors, under a range of true Net CONE values with over- or underestimated administrative Net CONE as summarized in Table 11. In a first test, we hold true Net CONE at the base value of \$11.08/kW-month, always adjusting supply until the long-term average price across simulation draws equals to that value no matter what the demand curve. We then vary the administrative Net CONE estimate by +/-20%, representing estimation error, as shown in Figure 16.³⁵ In second and third tests, we apply a +/-20% administrative Net CONE error under the alternative assumption that high E&AS offsets reduce true Net CONE to only \$4.43/kW-month (40% of the base value), both with and without a minimum value of $1 \times$ CONE (still \$14.03/kW-month) applied to the price cap.

³⁵ We specify the sensitivities by fixing true Net CONE rather than fixing administrative Net CONE so that cost outcomes would be comparable.

Figure 16
Proposed Curve with 20% Over- or Underestimated Net CONE
 Assuming True Net CONE Equals the Proposed Value of \$11.08/kW-month



The most important observation from these tests is that Net CONE estimation errors can have a substantial impact on reliability outcomes. Reliability impacts of estimation errors are asymmetric with respect to positive and negative estimation errors because shortage frequencies rise increasingly steeply as reserve margins fall below target (see Figure 7 in Section IV.E above). In the first test where true Net CONE is \$11.08/kW-month, a 20% underestimate worsens LOLE by 0.07 (to 0.17 events/yr), whereas an overestimate improves it by only 0.03 (to 0.07 events/yr). The second test, where high E&AS offsets reduce Net CONE to only \$4.43, also shows substantial sensitivity to +/-20% Net CONE estimation errors.

At lower Net CONE values, a 20% administrative estimation error has slightly less reliability impact because the higher elasticity of the capacity supply curve in that price range increases procurement quickly as prices rise. However, this test understates the reliability risks associated with Net CONE errors at low Net CONE, because a 20% error is small in absolute terms at +/- \$0.90/kW-month. When Net CONE is low, it is the difference between two large numbers, CONE and E&AS. Much larger percentage errors are conceivable under this scenario, caused either by errors in the CONE estimate or, possibly more importantly, the E&AS estimate. In that case, reliability outcomes could differ greatly from design objectives with a greater risk of producing low reliability outcomes. Applying the price cap minimum protects against this potential outcome, although it does result in exceeding the reliability objective if true Net CONE is low.

Under each of these tests, impacts on long-term average customer capacity procurement costs are small because average market clearing prices depend on suppliers' true Net CONE, not on administrative estimates or errors thereof. Capacity procurement costs change only because cleared quantities vary, causing customers to buy a little more or less

capacity. We show these customer cost increases or decreases schematically in Figure 16 as the blue and gray squares, respectively. For example, if true Net CONE is \$11.08/kW-month, overestimating Net CONE by 20% would increase capacity procurement costs by \$41 million per year, or only 1% of total capacity procurement costs; underestimating Net CONE by 20% would reduce costs by \$94 million per year, or about 2%.³⁶ Note that these capacity procurement cost impacts do not account for all of the energy costs or reliability-related costs that would change as reserve margins change, such as those we have described in a recent analysis conducted for the Commission.³⁷

Table 11
Performance of Proposed Curve with Errors in Administrative Net CONE Estimate

	Price			Reliability					Price * Quantity		
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Reserve Margin	Reserve Margin St. Dev.	Frequency Below NICR	Frequency Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	(\$/kW-m)	(\$/kW-m)	(% of draws)	(events/yr)	(%)	(%)	(% of draws)	(% of draws)	(\$mil/yr)	(\$mil/yr)	(\$mil/yr)
ISO-NE Proposed	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
True Net CONE = \$11.08/kW-m (Proposed)											
20% Overestimate	\$11.1	\$4.4	2.3%	0.073	14.8%	2.6%	16.0%	3.5%	\$4,467	\$2,275	\$7,072
Accurate Net CONE	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
20% Underestimate	\$11.1	\$2.7	22.9%	0.168	11.3%	2.9%	59.3%	25.3%	\$4,332	\$2,797	\$5,484
True Net CONE = \$4.43/kW-m (40% of Proposed)											
20% Overestimate	\$4.4	\$1.3	0.4%	0.066	14.8%	1.8%	8.4%	0.6%	\$1,791	\$1,161	\$2,556
Accurate Net CONE	\$4.4	\$1.1	1.8%	0.087	13.6%	1.9%	19.4%	2.6%	\$1,768	\$1,228	\$2,401
20% Underestimate	\$4.4	\$0.8	12.2%	0.141	11.5%	2.1%	59.6%	14.4%	\$1,736	\$1,282	\$2,168
True Net CONE = \$4.43/kW-m (w/ Gross CONE Minimum Cap)											
20% Overestimate									<i>Same as accurate Net CONE with Gross CONE Minimum Cap in effect</i>		
Accurate Net CONE	\$4.4	\$1.7	0.0%	0.037	17.3%	1.4%	0.4%	0.0%	\$1,828	\$1,046	\$2,891
20% Underestimate									<i>Same as accurate Net CONE with Gross CONE Minimum Cap in effect</i>		

Notes:

Average prices do not account for potential reductions in the cost of capital and Net CONE supported by more gradual demand curves. The reported Price * Quantity is the system price multiplied by the system total quantity and does not reflect zonal price differentials.

These observations point to three key insights important for designing the demand curve to reduce vulnerability to low reliability outcomes. The first and most obvious insight is that the administratively-determined Net CONE must be estimated as accurately as possible for the demand curve to achieve its resource adequacy objectives. It is particularly important to carefully avoid underestimating Net CONE, to avoid the asymmetrically high reliability risks. The Newell/Ungate Testimony focuses on identifying the right reference

³⁶ Understating Net CONE decreases customer capacity costs more than overstating Net CONE increases them because the cleared quantities are asymmetrically lower due to the kink in the curve at the cap. The price stops increasing once it reaches the cap, so the distribution of outcomes must shift leftward to achieve a greater frequency of low-quantity price cap events and maintain average prices at true Net CONE.

³⁷ See Pfeifenberger, Spees, Carden, and Wintermantel. (2013). *Resource Adequacy Requirements: Reliability and Economic Implications*. Available at http://www.brattle.com/system/publications/pdfs/000/004/984/original/Resource_Adequacy_Requirements_Pfeifenberger_Spees_FERC_Sept_2013.pdf?1392303166

technology and not overlooking costs or risks or overstating the revenues a developer would expect.

The second insight is that applying a minimum of $1 \times \text{CONE}$ to the price cap substantially reduces the risk of under-procuring when high E&AS revenues and low Net CONE would otherwise collapse the demand curve. This constraint on the cap supports the entire curve, since the curve is a straight line from the cap to the toe. As the bottom panel of Table 11 shows, the minimum cap prevents Net CONE estimation errors from reducing reliability. We also note that if Net CONE were to drop far below anticipated levels, to 40% of expected, then reliability would exceed the target even without estimation error. This is caused by a separate issue, reflecting the greater elasticity of the supply curve in the price range of a low Net CONE compared to our base case Net CONE assumptions, as discussed in Section VI.A above.

The third insight is that most of the reliability risks derive from the flatness of the demand curve, a significant tradeoff for mitigating price volatility and market power concerns. Whereas steeper curves (or partly-steeper convex curves) produce more volatile prices and tighter quantity outcomes, and therefore achieve a more similar reliability outcome over a range of Net CONE values and administrative errors in Net CONE. Flatter curves exhibit more price stability and better protection against exercise of market power, but at the expense of greater uncertainty in quantities, reliability outcomes, and somewhat greater customer cost increases if Net CONE is overestimated.

The ISO-NE proposed curve strikes an appropriate balance among these competing objectives. The selected curve is nearer the flatter end of the range of well-performing curves in order to achieve substantial price volatility and market power mitigation benefits. However, the greater quantity risk is also offset by the price cap minimum, which protects against the worst possible low reliability risks.

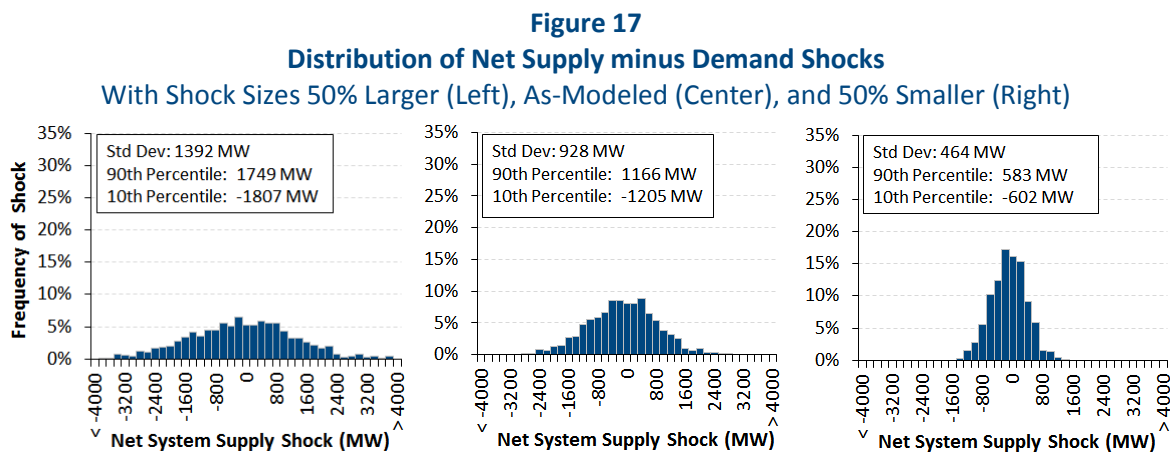
C. Sensitivity to the Magnitude of Supply and Demand Shocks

One of the key assumptions affecting the curve's performance is the magnitude of supply and demand shocks. Section IV.D described the distribution of shocks we used to test and calibrate the curve, with other sections illustrating the proposed curve's performance under those assumptions.

Although we have a strong historical basis for these assumed shock sizes, future shocks could be larger or smaller on average, either because of random variation or because of fundamental changes to the factors that give rise to shocks. For example, shock sizes may be impacted by future changes to environmental rules, business cycles, load forecast methods, or LOLE study methods. Or, market dynamics could differ from past dynamics, such that supply responds more (or less) readily to shocks, producing smaller (or larger) net shocks.

To test the robustness of the proposed curve to changes in the magnitude of shocks, we implement two sensitivity analyses in which the shock distributions are +/-50% of our base value. The standard deviations of supply minus demand in the "Larger Shock" and

“Smaller Shock” sensitivities are 1,392 and 464 MW, respectively, compared to 925 MW in the Base Case, as shown in Figure 17.



As expected, we find that with smaller shocks, price and reserve margin volatility are reduced, with reliability exceeding the 1-in-10 LOLE target by a small amount, with LOLE dropping by 0.017 to 0.083 events per year. With larger shocks, price and reserve margin volatility would be greater, and reliability would fall short of 1-in-10, with LOLE rising by 0.035 to 0.135 events per year. This shows significant sensitivity, although to a very large increase or decrease, to assumed shock sizes. The low reliability under the Larger Shock case is driven by the draws representing the 10% most extreme shortage events, which have net supply-demand shocks of -2,469 MW on average compared to -1,646 MW in the Base Case. We believe the reality will be much closer to the Base Case than the sensitivities, barring a large permanent change to underlying supply and demand fundamentals.

Table 12
Performance of Proposed Curves with Larger and Smaller Shocks to Supply and Demand

	Price			Reliability					Price * Quantity		
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Reserve Margin	Reserve Margin St. Dev.	Frequency Below NICR	Frequency Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	(\$/kW-m)	(\$/kW-m)	(% of draws)	(events/yr)	(%)	(%)	(% of draws)	(% of draws)	(\$mil/yr)	(\$mil/yr)	(\$mil/yr)
ISO-NE Proposed	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
Supply & Demand Shocks											
50% Larger	\$11.1	\$4.6	15.2%	0.135	13.2%	3.8%	36.0%	17.2%	\$4,393	\$1,961	\$6,820
50% Smaller	\$11.1	\$2.2	0.0%	0.083	13.6%	1.5%	18.9%	0.1%	\$4,425	\$3,249	\$5,651

Notes:

Average prices do not account for potential reductions in the cost of capital and Net CONE supported by more gradual demand curves. The reported Price * Quantity is the system price multiplied by the system total quantity and does not reflect zonal price differentials.

D. Interactions with ISO-NE's Pay for Performance Proposal

At the same time that ISO-NE will introduce a demand curve, it also plans to implement another major change to its capacity market if the Commission accepts its Pay for Performance (PFP) proposal.³⁸ PFP would pay or penalize all capacity resources \$2,000/MWh (a rate that would increase to \$5,445 over time) during shortages for their actual energy production or ancillary services provided relative to targets that are based on their capacity supply obligations (CSO) and the load at the time of the event. These new PFP mechanisms could affect capacity market outcomes and realized resource adequacy (in addition to operational performance) to the extent that they change resources' offer prices, the shape of the supply curve, and entry and exit decisions.

To assess how PFP would affect supply in ways that interact with the sloped demand curve, we reviewed and considered the implications of analyses ISO-NE had already conducted on resources' likely penalties and incentives under PFP.³⁹ Those analyses showed three important effects that will likely change capacity supply offers:

- All capacity supply offers will recognize that taking on a CSO exposes resources to penalties and reduces their potential rewards relative to not taking on a CSO and then receiving only incentives for over-performing against a zero obligation. This is the so-called "common value" component of supply offers because it is independent of unit-specific economics and performance. It creates a minimum price that any supplier will accept for taking on a CSO;
- Resources with poor availability and flexibility can expect to pay net penalties if they take on a CSO, whereas resources with high availability and flexibility can expect net rewards. Each resource's expected net PFP penalty or reward produces a "private value" adjustment to its capacity supply offer, but without reducing the offer below the common value; and
- The magnitude of the common value component depends on the Performance Payment Rate (PPR), the expected annual number of shortage events (H), and the "balancing ratio" based on the system load and fleet-wide output at the time of shortages; the magnitude of the private value adjustment depends on these three factors as well as the anticipated unit-specific power output (or provision of reserves) during these events.⁴⁰

³⁸ ISO-NE has filed its PFP proposal before the Commission, with associated provisions to be effective for FCA9 or the 2018/19 delivery year, pending approval of the Commission. See ISO-NE filings before the Commission on January 17, 2014 in Dockets ER14-1050-000, and -001.

³⁹ See the filing letter, testimonies, and supporting documentation under ISO-NE's filed before the Commission January 17, 2014 in Dockets ER14-1050-000, and -001.

⁴⁰ For a more comprehensive discussion of the common value component and private value adjustment, see Gillespie, Alivand, Coutu, and White presentation from April 9-10, 2013, posted at: http://www.iso-ne.com/committees/comm_wkgrps/mrktts_comm/mrktts/mtrls/2013/apr9102013/a17a_iso_presentation_04_10_13.ppt

Both of these components will affect individual resources' supply offers, although the "common value" component has a more substantial impact on the overall shape of the supply curve. This common value component introduces a minimum offer level that creates a long horizontal shelf in the supply curve as illustrated in Figure 18, and as previously documented.⁴¹

To test the impact of PFP on the performance of the proposed demand curve, we revised the anticipated supply curve shape over a range of potential PFP levels. We considered PPRs of \$2,000/MWh, \$3,500/MWh, and \$5,455/MWh, corresponding to PFP implementation Phase I starting 2018/19, Phase II starting 2021/22, and Phase III starting 2024/25, respectively. In each case, we assume $H = 21$ when the reserve margin is at NICR, corresponding to ISO-NE's base case assumption.⁴²

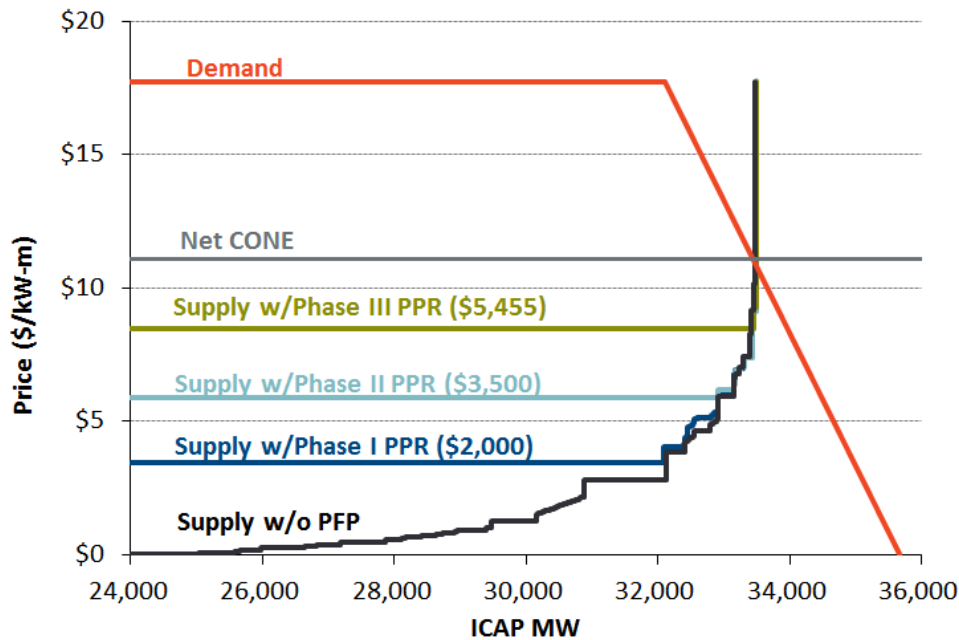
We find that the demand curve performs quite similarly with or without PFP. Adding PFP in combination with the demand curve results in a slight improvement to realized reliability and a slight reduction in capacity price volatility relative to the no-PFP case. For example, with $H = 21$ at NICR, the impact of PFP on clearing results and reliability is minor, with an LOLE of 0.1 without PFP improving to 0.098 with Phase I PPR, and 0.096 with Phase II PPR, as shown in Table 13. There is a somewhat larger improvement in reliability under Phase III PPR of \$5,455 with LOLE dropping to 0.084.

The small improvements in reliability under Phases I–II, and larger improvement under Phase III reflect operating capacity in excess of demand curve procurement in the draws where the market clears at the common value at the bottom of the supply curve, and also the benefits of increased supply curve elasticity. These improvements do not reflect any potential changes in unit performance, which are beyond the scope of this analysis. We conclude that these effects are small enough that no adjustments to the demand curve would be necessary upon the implementation of PFP, especially in Phase I and Phase II when the impacts are very small. Under Phase III, reliability outcomes would be improved as the frequency and magnitude of capacity operating in excess of cleared quantities increases, because some quantity of excess is supported by PFP incentives beyond what the demand curve alone would support.

⁴¹ To adjust the expected supply curve under each level of H and PPR, we adopt the same assumptions, method, and unit-specific output values, as were presented by ISO-NE and Schatzki/Hubbard in the January 17 PFP filing. See ISO-NE's filings before the Commission January 17, 2014 in Dockets ER14-1050-000, and -001, Attachment B "FCM Pay for Performance Impact Assessment," by Schatzki and Hibbard.

⁴² Our $H = 21$ assumption is adopted from an analyses conducted by ISO-NE staff. See *Id.*, Attachment I-1c, "Testimony of Matthew White on Behalf of the ISO," p. 107. We also recognize that H could be higher or lower under different assumptions with a substantial uncertainty band; however, we do not analyze sensitivity to these H values because our conclusions depend primarily on the realized value of the common value component, which is a function of PPR times H . Because we test a wide range of common value levels based on a substantial range in PPR from zero to \$5,455/MWh, the same conclusions can be used to evaluate the impacts of a fixed PPR and a wide range of H .

Figure 18
Simulated FCM Supply Curves under Pay for Performance



Sources and Notes:

Example supply curve without PFP along with the as-adjusted supply curve for the same curve. Our Monte Carlo simulations incorporate 1,000 different such curves.
 Each curve reflects H = 21 at NICR, based on analysis conducted by ISO-NE staff.
 Net CONE shown does not account for the small adjustment to Net CONE to account for net PFP payments.

Table 13
Performance of ISO-NE Curve in Combination with Proposed Pay for Performance Mechanism

	Price			Reliability				Price * Quantity			
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Reserve Margin	Reserve Margin St. Dev.	Frequency Below NICR	Frequency Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	(\$/kW-m)	(\$/kW-m)	(% of draws)	(events/yr)	(%)	(%)	(% of draws)	(% of draws)	(\$mil/yr)	(\$mil/yr)	(\$mil/yr)
ISO-NE Proposed	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
Pay for Performance											
Phase I PPR	\$11.1	\$3.7	6.4%	0.098	13.5%	2.7%	31.1%	6.9%	\$4,425	\$2,527	\$6,463
Phase II PPR	\$11.1	\$3.6	5.7%	0.096	13.7%	2.8%	31.1%	6.7%	\$4,423	\$2,635	\$6,445
Phase III PPR	\$11.1	\$2.9	4.4%	0.084	14.4%	3.1%	31.1%	5.0%	\$4,432	\$3,366	\$6,273

Notes:

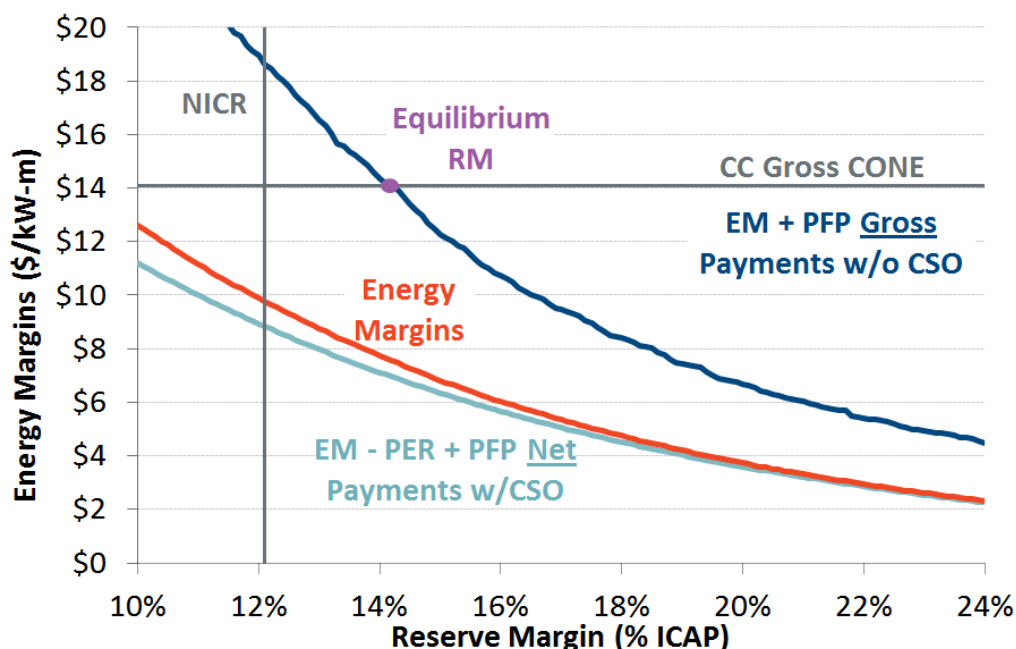
Average prices do not account for potential reductions in the cost of capital and Net CONE supported by more gradual demand curves.
 The reported Price * Quantity is the system price multiplied by the system total quantity and does not reflect zonal price differentials.

It is also possible to imagine a scenario under which PFP common value becomes high enough (or Net CONE becomes low enough) that the PFP common value would exceed Net CONE. Under such a scenario, the ISO-NE market could shift toward an energy-only-like market as summarized in the illustrative example in Figure 19. The chart shows a schematic example where: (a) the payment rate is at the Phase III with PPR=\$5,455/MWh; (b) H = 21 hours as estimated by ISO-NE; and (c) energy market fundamentals tighten so that CC energy margins rise to a higher level of \$9.77/kW-m.

Under this scenario, energy margins plus PFP gross payments at NICR could exceed gross CONE, inducing new plants to enter without a CSO. More plants would enter the market until scarcity hours and energy margins would drop, and total incentives are just enough to earn back investment costs. Reserve margin and reliability outcomes would then be determined by the relationship between shortage hours and reserve margin (like an energy-only market), rather than the capacity market demand curve. Such an outcome would result in an equilibrium reserve margin that substantially exceeds NICR. This would render a demand curve superfluous in most years, although the curve would still protect against the possibility of low reliability events. We therefore recommend the same demand curve with or without PFP, in all phases of implementation.

Figure 19

Illustrative Example Equilibrium in a High PFP Payments and High Energy Margin Scenario



Notes:

An example equilibrium is shown, with PPR = \$5,455/MWh and energy margins higher than anticipated.

At NICR or 12.1% reserve margin, CC Energy Margins = \$9.77/kW-month, and H = 21.

Market reaches equilibrium at a higher reserve margin of 14.2%, with energy margins = \$7.56/kW-month and H = 15.9.

The dark blue line reflects net investment incentives to a supplier who does not sell capacity, including: (a) energy margins, plus (b) PFP gross payments (but without PFP penalties, which are only assessed to those that sell capacity).

The light blue line reflects investment incentives (other than capacity payments) to a supplier who does sell capacity including: (a) energy margins, plus (b) PFP payments, minus (c) Peak Energy Rent (PER) deductions, minus (d) PFP penalties. Note that in this case the capacity clearing price would be equal to PER plus PFP common value (difference between dark and light blue lines).

E. Summary of Performance under Sensitivity Scenarios

We believe that the demand curve proposed by ISO-NE in this docket is a well-designed curve that strikes an appropriate balance among competing design objectives and will perform well under a range of market conditions that ISO-NE may face in the future. Table 14 summarizes this performance as discussed in the prior sections, under a wide range of Net CONE levels, administrative errors to Net CONE, different assumed shocks, and different phases of PFP implementation.

The area where performance varies most with system conditions and study assumptions is in cleared quantities, which is a consequence of the curve being on the flatter end of the spectrum of well-performing curves. This introduces some risk of lower reliability in the event that administrative Net CONE is underestimated, but the minimum price cap provides some protection against under-procurement. The flatter curve could also over-procure under some scenarios we examined, although the capacity procurement cost impacts would be small. This variation in quantity outcomes across sensitivity scenarios, while greater than with some steeper or kinked curves we examined, is a natural characteristic of a sloped demand curve that mitigates price volatility and exposure to market power abuse as much as this one does.

Overall, we believe the proposed curve will continue to perform well over anticipated near-term market conditions as well as under a range of conditions that may be experienced over the coming years.

Table 14
Performance of Proposed Curve under Varying System Conditions and Modeling Uncertainties

	Price			Reliability					Price * Quantity		
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Reserve Margin	Reserve Margin St. Dev.	Frequency Below NICR	Frequency Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	(\$/kW-m)	(\$/kW-m)	(% of draws)	(events/yr)	(%)	(%)	(% of draws)	(% of draws)	(\$mil/yr)	(\$mil/yr)	(\$mil/yr)
ISO-NE Proposed	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
System Net CONE											
120% of Proposed	\$13.3	\$4.6	7.0%	0.101	13.4%	2.8%	30.4%	8.9%	\$5,312	\$2,829	\$7,834
80% of Proposed	\$8.9	\$2.8	6.6%	0.099	13.5%	2.6%	29.4%	7.6%	\$3,543	\$2,135	\$5,157
40% (Cap at Gross CONE)	\$4.4	\$1.7	0.0%	0.037	17.3%	1.4%	0.4%	0.0%	\$1,828	\$1,046	\$2,891
40% (No Gross CONE Min.)	\$4.4	\$1.1	1.8%	0.087	13.6%	1.9%	19.4%	2.6%	\$1,768	\$1,228	\$2,401
True Net CONE = \$11.08/kW-m (Proposed)											
20% Overestimate	\$11.1	\$4.4	2.3%	0.073	14.8%	2.6%	16.0%	3.5%	\$4,467	\$2,275	\$7,072
Accurate Net CONE	\$11.1	\$3.7	6.4%	0.100	13.5%	2.7%	31.4%	7.4%	\$4,426	\$2,492	\$6,472
20% Underestimate	\$11.1	\$2.7	22.9%	0.168	11.3%	2.9%	59.3%	25.3%	\$4,332	\$2,797	\$5,484
True Net CONE = \$4.43/kW-m (40% of Proposed)											
20% Overestimate	\$4.4	\$1.3	0.4%	0.066	14.8%	1.8%	8.4%	0.6%	\$1,791	\$1,161	\$2,556
Accurate Net CONE	\$4.4	\$1.1	1.8%	0.087	13.6%	1.9%	19.4%	2.6%	\$1,768	\$1,228	\$2,401
20% Underestimate	\$4.4	\$0.8	12.2%	0.141	11.5%	2.1%	59.6%	14.4%	\$1,736	\$1,282	\$2,168
True Net CONE = \$4.43/kW-m (w/ Gross CONE Minimum Cap)											
20% Overestimate				<i>Same as accurate Net CONE with Gross CONE Minimum Cap in effect</i>							
Accurate Net CONE	\$4.4	\$1.7	0.0%	0.037	17.3%	1.4%	0.4%	0.0%	\$1,828	\$1,046	\$2,891
20% Underestimate				<i>Same as accurate Net CONE with Gross CONE Minimum Cap in effect</i>							
Supply & Demand Shocks											
50% Larger	\$11.1	\$4.6	15.2%	0.135	13.2%	3.8%	36.0%	17.2%	\$4,393	\$1,961	\$6,820
50% Smaller	\$11.1	\$2.2	0.0%	0.083	13.6%	1.5%	18.9%	0.1%	\$4,425	\$3,249	\$5,651
Pay for Performance											
Phase I PPR	\$11.1	\$3.7	6.4%	0.098	13.5%	2.7%	31.1%	6.9%	\$4,425	\$2,527	\$6,463
Phase II PPR	\$11.1	\$3.6	5.7%	0.096	13.7%	2.8%	31.1%	6.7%	\$4,423	\$2,635	\$6,445
Phase III PPR	\$11.1	\$2.9	4.4%	0.084	14.4%	3.1%	31.1%	5.0%	\$4,432	\$3,366	\$6,273

Notes:

Average prices do not account for potential reductions in the cost of capital and Net CONE supported by more gradual demand curves. The reported Price * Quantity is the system price multiplied by the system total quantity and does not reflect zonal price differentials.

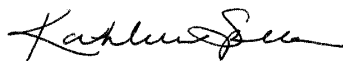
VII. CERTIFICATION

We hereby certify that we have read the filing signed and know its contents are true as stated to the best of our knowledge and belief. We possess full power and authority to sign this filing.

Respectfully Submitted,



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April 1, 2014

PJM CONE study² and provided affidavits in ensuing litigation,³ which informed the Net CONE values PJM used in its capacity auctions for the 2016/2017 and 2017/2018 delivery years. For NYISO, Mr. Ungate developed capital cost and fixed O&M cost estimates for the demand curve reset studies of 2008, 2011, and 2013.⁴ In addition, Dr. Newell's extensive related experience in market design for resource adequacy for ISO-NE, PJM, NYISO, MISO, and ERCOT has provided broad perspective on the capacity market context in which Net CONE is used.

Our experience working for RTOs is also informed by our work for market participants building, buying, and contracting with generation plants. Dr. Newell has led numerous generation asset valuation studies and resource planning studies. Mr. Ungate has performed a number of utility planning studies for clients, and he supports ISOs and utility clients with cost and performance estimates of new entrant technologies that are used in the development of administratively determined demand curves and power supply plans.

Dr. Newell is an economist and engineer with more than 15 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and RTO market rules. Prior to joining The Brattle Group, he was the Director of the Transmission Service at Cambridge Energy Research Associates and previously a Manager in the Utilities Practice at A.T.Kearney. He earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and a B.A. in Chemistry and Physics from Harvard College.⁵

Mr. Ungate has over thirty-five years of experience in electric utility operations, planning, and consulting. Prior to joining Sargent & Lundy, he was manager of generation resource planning at the Tennessee Valley Authority. He directed supply planning for 30,000 MW of nuclear, coal, gas, renewable, and hydro generation, and determined peak season power purchase requirements. He has a B.S. and M.S. in Civil Engineering from the Massachusetts Institute of Technology, and an M.B.A. from the University of Tennessee at Knoxville. He is a registered professional engineer in the State of Tennessee.

Complete details of our qualifications, publications, reports, and prior experiences are set forth in our resumes, listed as attachments to ISO-NE's filing letter.

² Kathleen Spees, Samuel Newell, Robert Carlton, Bin Zhou, and Johannes Pfeifenberger, *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM*, August 24, 2011. ("2011 PJM CONE Study") Available at <http://www.pjm.com/documents/reports.aspx>.

³ Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, *Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, supporting PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's Reliability Pricing Model*, November 21, 2012.

⁴ Before the Federal Energy Regulatory Commission, Docket No. ER14-500-000, *Affidavit of Christopher D. Ungate on Behalf of New York Independent System Operator, re: answer to protests that challenged its November 29, 2013, filing of Proposed Tariff Revisions to Implement Revised ICAP Demand Curves and a New ICAP Demand Curve for Capability Years 2014/2015, 2015/2016 and 2016/2017*, January 7, 2014.

⁵ A more comprehensive biography and list of publications is available here: <http://www.brattle.com/experts/samuel-a-newell>.

TABLE OF CONTENTS

I. Executive Summary	5
II. Introduction.....	8
A. Background	8
B. Scope.....	9
III. Methodology	9
A. Net CONE Estimation Objective	9
B. Analytical Approach	10
C. Selecting the Reference Technology	11
1. Principles for Evaluating Potential Reference Technologies.....	12
2. Additional Considerations in Selecting Reference Technologies.....	14
3. Comparison to NYISO and PJM Reference Technology Approaches	15
D. Technology Screening	16
1. Technologies Evaluated	16
2. Technologies Not Evaluated.....	18
E. Estimating Net CONE for Candidate Reference Technologies.....	19
IV. Technical Specifications of Candidate Technologies.....	20
A. General Approach	20
B. Explanation of Key Assumptions	20
1. Location Selection	20
2. Site Conditions.....	23
3. Environmental Requirements and Implications.....	24
4. Plant Configuration.....	25
5. Fuel Assumptions.....	26
6. Cooling System.....	27
7. Supplemental Firing.....	27
8. Evaporative Cooling	28
9. Electrical Interconnection	28
C. Summary of Specifications for Each Candidate Reference Technology.....	29
1. Technical Specifications	29
2. Performance and Operating Capabilities	29
V. Capital Costs.....	30
A. EPC Costs	31
1. Equipment and Sales Tax.....	31
2. Labor and Materials	31
3. EPC Contractor Fee and Contingency	31
B. Owner’s Capital Costs	32
1. Owner’s Cost (Services)	32
2. Gas Interconnection	32
3. Electric Interconnection.....	33
4. Financing Fees	34
5. Working Capital and Fuel Inventory	34
6. Owner’s Contingency	34
C. Escalation to 2018 Overnight and Installed Costs	34
D. Summary of Capital Costs	35

VI. Operating and Maintenance Costs	37
A. Fixed O&M	37
B. Variable O&M	38
C. Escalation to 2018 O&M Costs	38
D. Implications for Economic Life	39
E. Summary of O&M Costs	39
VII. CONE Calculations	40
A. Long-Term Market View	40
B. Economic Life.....	42
C. Cost of Capital	42
D. Other Financial Assumptions.....	46
E. Summary of CONE Values.....	47
VIII. Revenue Offsets	48
A. Approach.....	48
B. Historical E&AS Margins.....	50
1. Combined Cycle Historical E&AS Margins.....	50
2. Combustion Turbines Historical E&AS Margins	52
C. E&AS Margin Adjustment using Futures Settlement Prices.....	56
D. Effect of PER and PFP on Revenue Offsets	59
E. Summary of Revenue Offsets	62
IX. Summary of Net CONE Results	63
X. Recommended Net CONE for the Demand Curve	63
A. Recommended Reference Technology	63
B. Recommended Net CONE.....	65
XI. Locational Net CONE	65
A. Approach.....	65
B. NEMA/Boston	66
C. Connecticut	66
XII. Annual Update Process	66
A. Indices for Capital and Fixed O&M Costs	66
B. Updates on Revenue Offsets.....	67
XIII. Certification	68

I. EXECUTIVE SUMMARY

This testimony presents estimates of the Net Cost of New Entry (Net CONE) for use in the sloped demand curve ISO-NE is proposing to replace the vertical demand curve in its Forward Capacity Market (FCM). As explained in the Newell/Spees Testimony attached to this same filing, the sloped demand curve is intended to procure sufficient capacity to maintain resource adequacy while also mitigating price volatility and susceptibility to market power abuse. The prices and quantities of the proposed curve are premised on the assumption that, in a long-term economic equilibrium, new entrants will set average capacity market prices at Net CONE—where Net CONE is the first-year capacity revenue a new generation resource would need (in combination with expected energy and ancillary services margins) to recover its capital and fixed costs, given reasonable expectations about future cost recovery under continued equilibrium conditions. Thus, in order to achieve the desired reserve margin, the sloped demand curve is assigned a price equal to Net CONE at approximately the point where the quantity equals the desired average reserve margin.⁶ This testimony provides an estimated Net CONE value for that purpose.

The Newell/Spees Testimony shows that the proposed curve can be expected to achieve ISO-NE's resource adequacy objectives if the estimated Net CONE value accurately represents the true value that new entrants would need to enter the market. That testimony also shows that overstating Net CONE would result in procuring more capacity than needed with only modest cost implications, whereas understating it would result in under-procuring capacity and significantly diminished system reliability with average prices set by true Net CONE in both cases. Thus, we aim to estimate Net CONE as accurately as possible with particular care not to significantly understate it.

One of the most important factors in estimating Net CONE is selecting an appropriate reference technology on which to base the estimate. Although several technologies are likely to be built in a long-term equilibrium, each with the same long-term average Net CONE, in practice it is difficult to project which technologies will be part of that mix. In addition, Net CONE estimates can differ substantially among technologies due to temporary disequilibrium market conditions and estimations errors. Thus, our approach to estimating Net CONE for ISO-NE started with defining high-level principles and specific criteria for selecting a reference technology. The reference technology must: (1) be able to reliably help meet load when installed capacity is scarce; (2) likely be economic for merchant entry under long-term equilibrium market conditions; and (3) be amenable to estimation of Net CONE with relatively low uncertainty. We also emphasize the importance, when setting Net CONE, of not switching back and forth to whatever reference technology has the lowest Net CONE

⁶ See Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of ISO New England, Inc. Regarding a Forward Capacity Market Demand Curve. FERC Docket No. ER14-____-000, April 1, 2014 ("Newell/Spees Testimony"). As the Newell/Spees Testimony shows, the price equals Net CONE at the Net Installed Capacity Requirement (NICR) + 1.4% in order for the curve to achieve the target 0.1 Loss of Load Expectation (LOLE) on average across the distribution of simulated auction outcomes. The mean of the distribution of reserve margins has to exceed NICR in order to achieve 0.1 LOLE on average because LOLE is a non-linear function of reserve margin, with lower reserve margins having a disproportionately large effect.

in future auctions. These principles support the objectives of the FCM and were developed through extensive discussions with ISO-NE staff and stakeholders.

We screened many candidate reference technologies and closely evaluated four that pass most of the criteria: a combined-cycle gas turbine (CC), an F-class frame combustion turbine (Frame CT), and two aeroderivative CT models (LM6000 and LMS100). Our evaluation included a detailed analysis of the technical specifications, capital and operating costs, and market outlook for each of these four technologies. Most aspects of the analysis were informed by extensive stakeholder input, which we solicited through several meetings with the NEPOOL Markets Committee meetings.

We determined that combined-cycle gas turbines (CCs) best meet the above principles and should be used as the reference technology in setting ISO-NE's demand curve. CCs are the predominant technology being built by merchant investors throughout the U.S., including the one plant in advanced development in New England. CCs are clearly an economic choice and are part of the mix of technologies that merchant investors will build. Calibrating the demand curve to their costs should procure the intended amount of capacity and best meet FCM's objectives. Moreover, we are confident in the accuracy of our estimate of CC Net CONE due to the standardized plant configuration and pricing for that technology. We also find that the uncertainty about its non-capacity revenue offsets is no higher than for the other candidate reference technologies in New England.

We also considered selecting the Frame CT, which had a lower estimated Net CONE than CCs in the New England market. Although other RTOs use the Frame CT for defining their demand curves, ISO-NE does not share their tariff specifications nor their history with sloped demand curves. As ISO-NE now introduces its own sloped demand curve, we believe that selecting the CC as the reference technology will better serve the FCM objectives. We note that merchant generators are not constructing the Frame CT in spite of its lowest apparent Net CONE. If the Frame CT's lack of entry indicates that its true Net CONE exceeds our estimate for any reason (*e.g.*, if merchant generators perceive risks or weaker long-term value than for a CC), selecting it as the reference technology could set the demand curve too low. The administrative Net CONE would be below the true Net CONE of potential CT or CC entrants, resulting in likely under-procurement. Our concern about this possibility is heightened by the findings in the Newell/Spees Testimony that under-estimating Net CONE can significantly compromise reliability, whereas over-estimating Net CONE has only modest cost implications.

The aeroderivative CTs had much higher Net CONE estimates, which makes it even less plausible that merchant developers will rely on them as a standard generation technology (unless they have uniquely advantageous siting or turbine purchasing opportunities). Setting Net CONE on the demand curve at the Net CONE of an aeroderivative CT would likely lead to over-procurement. Developers would like build excess capacity using the more economic CCs and Frame CTs until capacity prices declined to the lower Net CONE values of those technologies.

The Net CONE estimates we developed are based on a complete plant design consistent with current best-practices and environmental compliance. We conducted a comprehensive, bottom-up analysis of capital costs to build the plant: both the engineering, procurement, and construction (EPC) costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, gas

and electric interconnection costs, and inventories. We separately estimated annual fixed operating and maintenance costs, including labor, materials, property taxes, and insurance.

We translated the estimated costs into the annualized average net revenues the resource owner would have to earn over an assumed 20-year economic life to earn its required return on and of capital, assuming an after-tax weighted-average cost of capital (ATWACC) of 8% for a merchant investor, which we estimated based on various reference points. The resulting value, which we refer to as the gross cost of new entry, or CONE, indicates what a resource owner would need to expect to earn from all revenue sources in year one under the reasonable assumption that market fundamentals will allow the resource to continue earning the same amount in real terms on average over the rest of its economic life.

Next, we projected the net non-capacity revenues the plant can expect to earn in 2018/2019, including energy and ancillary services (E&AS) margins, pay-for-performance (PFP) payments under ISO-NE's PFP proposal, and peak energy rent (PER) deductions. E&AS margins are based on historical margins for similar plants, adjusted for differences in electricity prices indicated by available futures settlement prices. PFP payments and PER deductions are estimated based on an assumed number of scarcity hours (H) consistent with analysis ISO-NE conducted and our consideration of forward market heat rates.

Finally, we subtracted estimated net non-capacity revenues from CONE to arrive at Net CONE, the amount of capacity revenues the resource would need in year one to enter. The results are summarized below for CCs and for the three other reference technologies we evaluated.

Candidate Reference Technology Net CONE Summary for the New England Market (2018\$)

Reference Technology	Installed Capacity	Overnight Cost	Capital Costs	Fixed O&M	Gross CONE	E&AS Offsets	PER/PFP Offsets	Net CONE
<i>Rest of Pool</i>	<i>MW</i>	<i>\$/kW</i>	<i>\$/kW-mo</i>	<i>\$/kW-mo</i>	<i>\$/kW-mo</i>	<i>\$/kW-mo</i>	<i>\$/kW-mo</i>	<i>\$/kW-mo</i>
4x0 LM6000	173	\$1,965	\$17.91	\$3.26	\$21.18	\$1.67	-\$0.37	\$19.88
2x0 LMS100	188	\$1,711	\$15.60	\$2.85	\$18.45	\$1.69	-\$0.37	\$17.13
2x0 Frame CT	417	\$902	\$8.21	\$1.55	\$9.76	\$1.66	-\$0.37	\$8.47
2x1 CC	715	\$1,178	\$11.59	\$2.44	\$14.04	\$3.33	-\$0.37	\$11.08

Source: See Table 27 in Section IX.

The CC Net CONE of \$11.08/kW-month is the Net CONE value we recommend for setting the price points on the ISO-NE system-wide demand curve in its ninth forward capacity auction (FCA9). We also recommend using this value for the administrative pricing rules that we understand will remain in place in the import-constrained zones in FCA9 (until zonal demand curves are implemented for future auctions). Although the \$11.08/kW-month estimate is based on a reference location in central Massachusetts, our high-level analysis of Net CONE in NEMA/Boston and Connecticut indicates insignificant differences from the system-wide value.

ISO-NE plans to use our recommended Net CONE value for FCA9 and apply simple escalation factors for use in FCA10 and FCA11 to track changes in capital costs and energy market conditions. We recommend escalating capital costs using various producer price

indexes (PPI) and Quarterly Census of Employment and Wages (QCEW) indexes from the Bureau of Labor Statistics for the cost categories. We recommend adjusting non-capacity revenue offsets using updated electricity forward curves from the Intercontinental Exchange (ICE). A spreadsheet model we provided ISO-NE and stakeholders will facilitate this update process.

For FCA12, ISO-NE plans to conduct a new study. At that time, we recommend that ISO-NE adhere to the principles we established, while also considering new information. We discourage frequently switching reference technologies based on changes in relative Net CONE estimates (which could change due to estimation error or transient market conditions) as doing so could cause under-procurement. However, if merchant developers introduce frame-type turbines to New England over the next several years, ISO-NE should consider averaging the technology's Net CONE together with that of a CC for setting the demand curve Net CONE. Averaging the Net CONE of more than one technology that meets the reference technology principles may provide a more stable and efficient basis for setting prices on the demand curve than using the Net CONE of a single technology.

II. INTRODUCTION

A. Background

ISO New England (ISO-NE) is proposing a sloped demand curve for its ninth Forward Capacity Auction (FCA9) to replace the vertical demand currently used previously in its Forward Capacity Market (FCM). The proposed sloped demand curve would achieve ISO-NE's resource adequacy objectives, but with less price volatility and susceptibility to market power than a vertical curve. The details of the demand curve are described in concurrently submitted Newell/Spees Testimony.

As described in the Newell/Spees Testimony, the demand curve's price-quantity locus is designed to meet resource adequacy objectives under the standard economic assumption that, in a long-run equilibrium, prices will be set by the long-run marginal cost of supply. Thus, the curve seeks to procure approximately the target reserve margin at a price corresponding to the long-run marginal cost—or a little more capacity if low-cost supply is plentiful, and a little less if supply is scarce.⁷ As such, the prices on the curve are indexed to the long-run marginal cost of supply.

The long-run marginal cost of supply is often called the “Cost of New Entry” (CONE). CONE is the amount of annual net revenue a new capacity resource would need to earn from selling capacity, energy, and ancillary services to be economically viable and willing to enter the market. “Net CONE” is the portion the entrant would expect to earn solely from the capacity market as opposed to energy and ancillary services (E&AS) markets. Quantifying a Net CONE value that is appropriate for defining the pricing parameters in ISO-NE's proposed demand curve is the subject of our testimony.

⁷ As the Newell/Spees Testimony explains, the curve would actually procure slightly more than the Net Installed Capacity Requirement (NICR) on average so that the long-term average frequency of load-shedding events is no more than once in ten years, in spite of likely fluctuations in supply and demand that have asymmetric reliability implications.

B. Scope

In this testimony, we recommend a Net CONE value for use in ISO-NE's proposed system-wide demand curve and in the remaining administrative pricing rules in its Forward Capacity Market. To do so, we establish principles and specific criteria for selecting a reference technology for defining Net CONE. For each candidate reference technology that meets the criteria, more or less, we estimate their Net CONE based on a bottom-up analysis of expected costs and revenues. We then recommend a reference technology and associated Net CONE value that we believe best meets the principles and the overall objectives of ISO-NE's FCM.

We also show that Net CONE in the import-constrained sub-regions of Connecticut and NEMA/Boston is negligibly different from the system-wide value. Although ISO-NE is not yet proposing demand curves for meeting their local resource adequacy requirements, it can use the system-wide value as an input for determining price caps and other administrative pricing rules until zonal demand curves replace them.

Finally, we provide a simple escalation method ISO-NE can use to set Net CONE for the following two FCAs so that Net CONE tracks capital costs and changes in energy market conditions. The updated values could be used in FCA10 and FCA11 for the system-wide demand curve and for zonal demand curves if applicable. A new study would be conducted to estimate Net CONE for FCA12 and beyond.

Our scope also included extensive solicitation of input from ISO-NE stakeholders through presentations to the New England Power Pool Markets Committee. We presented at the stakeholder meetings our initial analysis (January 14), responses to two sets of stakeholder comments (February 4 and 11), additional responses and our draft proposal (February 27), and our final proposal (March 12). Stakeholders provided comments at those meetings and in subsequent correspondence, all of which the study authors reviewed. Their input is included in the proposed Net CONE and/or addressed in this report.

III. METHODOLOGY

A. Net CONE Estimation Objective

Our methodology starts with defining the "Net CONE estimation objective" by considering the role that Net CONE plays in ISO-NE's proposed demand curve.

The ISO-NE sloped demand curve was designed to attract and retain sufficient capacity to maintain resource adequacy by providing high capacity prices when reserve margins are low and low prices where reserve margins are high. The curve is calibrated to meet resource adequacy objectives in part by indexing the prices on the curve to Net CONE, which is the estimated capacity price a new generation resource would need in order to enter the market.

Net CONE must be estimated accurately in order to meet the resource adequacy and cost objectives of the sloped demand curve. Understating the true value leads to a lower demand curve with suppliers building less and setting prices higher than the administrative Net CONE, and with ISO-NE procuring insufficient resources. Understating Net CONE

produces substantially lower system reliability, since expected shortage frequencies become increasingly steep as reserve margins fall below target. Our simulations show that if Net CONE were under-estimated by 20%, the market would clear at a 2.2% lower reserve margin on average, and LOLE would deteriorate to 0.17 instead of the target of 0.10.⁸

Conversely, if Net CONE were overstated, suppliers would enter readily and set prices lower than the administrative Net CONE, and the quantity cleared in the auction would exceed targets. Customers would not have to pay higher prices, but they would procure surplus capacity that has diminishing value. For example, the Newell/Spees Testimony shows that a 20% overestimation error would lead to a 1.3% higher reserve margin, costing customers about 0.9% more for capacity.⁹

In either case, the rational economic expectation is for long-term average capacity prices to be set by the true Net CONE new entrants need even if administrative Net CONE is higher or lower. However, setting the demand curve based on an inaccurate estimate of Net CONE will procure more or less supply than intended. The marginal net costs of over-procuring capacity appear less significant than the non-linear reliability impacts of under-procuring.

Given that understanding of the role of the Net CONE in the sloped demand curve, our Net CONE estimation objective is to set capacity market prices just high enough to meet resource adequacy objectives by calculating Net CONE as accurately as possible, with particular care not to significantly understate it. We aim to select a reference technology that is likely to enter the market, and to accurately account for competitive developers' costs, risks, and a reasonable long-term view of the market when calculating Net CONE.

B. Analytical Approach

We developed a set of high-level principles and specific criteria for selecting a reference technology that meets the Net CONE estimation objective. As discussed below, we defined the principles to ensure that the reference technology is able to contribute to resource adequacy, that merchant generators are likely to build it, and that its Net CONE can be estimated accurately. The specific criteria provide further details on the requirements for meeting the principles.

For each of three technologies that pass most of the criteria, we developed a detailed Net CONE estimate.¹⁰ We aim to capture in the Net CONE analysis all of the factors that a developer would consider in estimating the first-year capacity revenue they would need to enter the market. The main components of our analysis are:

1. Characterization of the technical specifications of the plant, based on analysis of current technologies and environmental requirements;
2. Bottom-up assessment of capital costs and fixed operations and maintenance (fixed O&M) costs;

⁸ Newell/Spees Testimony.

⁹ Newell/Spees Testimony.

¹⁰ Stakeholders requested that a single technology that had not passed the screening, a General Electric LM6000 aeroderivative combustion turbine, be added to our analysis.

3. Translation of those costs into CONE, the total capital and fixed cost recovery needed in year one given various financial assumptions and expectations about the future;
4. Projection of the net non-capacity revenues the plant can expect to earn in 2018/2019, including energy and ancillary services (E&AS) margins, pay-for-performance (PFP) payments, and peak energy rent (PER) deductions; and
5. Calculation of Net CONE, which is simply CONE minus the net non-capacity first-year revenues.

Finally, we consider all of the evidence and recommend a reference technology and Net CONE value for setting the system-wide demand curve for FCA9.

Our analysis focuses primarily on the rest-of-pool (ROP) region, not the import-constrained zones of Connecticut and NEMA/Boston, nor the export-constrained zone of Maine. To assess whether Net CONE would differ significantly in those locations, we confirm that plant configurations would likely be the same, and we consider differences in labor and land costs.

Our approach to calculating Net CONE is similar to our approach for the ISO-NE 2013 Offer Review Trigger Price (ORTP) Study, but with a few significant differences reflecting the different objectives of the demand curve. First, we are estimating a Net CONE value that is representative of an expected competitive entrant, and not one “at the low end of competitive offers,” as we did for the ORTP study.¹¹ This change in approach is reflected in our assumptions about plant location and capital costs. For ORTP we sought out locations with low labor costs and ideal siting for interconnections. In this study, we located the plant in a location that is representative of the wider ROP capacity zone. Second, we are assuming in this analysis that new capacity is developed as a pure-play merchant project that is not supported by a power purchase agreement (PPA) and thus has a higher cost of capital. Third, our Net CONE estimate has been informed by a stakeholder process that elicited extensive additional input on various details regarding costs and revenues of the candidate reference technologies.

C. Selecting the Reference Technology

A wide range of capacity resources participate in ISO-NE’s Forward Capacity Market, including fossil, nuclear, and renewable generation, and demand-side energy efficiency and demand response resources. However, some resource types are more appropriate than others as reference technologies for determining Net CONE for the demand curve.

Below, we describe the principles and specific criteria for evaluating candidate reference technologies. We also discuss additional considerations that we believe are important when selecting the reference technology or technologies. Finally, we compare the approach we are recommending for ISO-NE to the approaches used in other RTOs with demand curves.

¹¹ Samuel A. Newell, J. Michael Hagerty, and Quincy X. Liao, *2013 Offer Review Trigger Prices Study*, October 2013. (“2013 ORTP Study”) Available at http://www.brattle.com/system/publications/pdfs/000/004/981/original/2013_Offer_Review_Trigger_Prices_Study_Newell_Hagerty_Liao_ISONE_Oct_2013.pdf.

1. Principles for Evaluating Potential Reference Technologies

With stakeholder input, we developed the following principles and specific criteria for selecting the Net CONE reference technologies, as shown in Table 1.

Table 1
Principles and Criteria for Selecting the Reference Technology

Principle	Criteria
Reliably able to help meet load when installed capacity is scarce	<ul style="list-style-type: none"> – Complies with all environmental regulations – Dispatchable technology that could be available to generate whenever installed capacity is scarce
Economic for merchant entry as part of long-term equilibrium	<ul style="list-style-type: none"> – Available as standardized, utility-scale commercial plants without inherent constraints on the amount of capacity that could enter – Demonstrated commercial interest by merchant developers – Estimated Net CONE is not so high as to make it implausible that the technology would be part of the long-term mix of resources entering the market
Can estimate Net CONE with low uncertainty	<ul style="list-style-type: none"> – Cost estimates have low uncertainty, based on established, standardized technologies – E&AS estimates have low uncertainty relative to other technologies

The first principle is that the reference technology must be **reliably able to help meet load when installed capacity is scarce**. This ensures that the benchmark Net CONE price describes the cost of adding a unit of capacity that can meet the central objective of the capacity market, which is to have enough supply even when load is high and installed reserves become scarce. It does not address performance capabilities (or lack thereof) such as ramp rates that contribute to operational reliability needs that are not traditionally considered part of resource adequacy.

We established two criteria to determine whether the reference technology is able to reliably help meet load when installed capacity is scarce. First, the technology must *comply with all environmental regulations* set by the locality in which it operates. Environmental regulations can prevent certain plant configurations from obtaining a construction permit, or can also impose run-time restrictions on high-emitting plants. In evaluating reference technologies, we exclude any technologies that are unable to be built due to environmental regulations, and we disfavor technologies whose run time may be very limited.

Second, the reference technology must be a *dispatchable technology that could be available to ISO-NE operators to generate whenever installed capacity is scarce*. While non-dispatchable, intermittent technologies can provide capacity value to the system, we do not believe that the capacity demand curve should be based on a technology that the system operators would not be able to call upon at any time to provide capacity in scarcity hours.

The second principle is that the reference technology must be **economic for merchant entry as part of the long-term equilibrium**. This principle acknowledges that uneconomic technologies will have a higher cost and would set Net CONE higher than needed to achieve resource adequacy objectives, leading to over-procurement. However, it does not suggest that the technology with the lowest Net CONE should always be selected, as that practice could under-procure on average, as discussed in the following section.

We established three criteria to determine whether the reference technology is likely to be economic as part of the long-term equilibrium. First, the reference technology must be *available as standardized, utility-scale commercial plants without inherent constraints on the amount that could enter*. While some technologies may be in earlier stages of development or available commercially only at small scales, for a resource to be a part of the long-term equilibrium it must be able to be built at a scale that can be widely deployed to meet ISO-NE resource adequacy. Relatedly, the technology cannot have inherent constraints on its ability to provide the required capacity to meet resource adequacy objectives as such a resource cannot fundamentally represent the long-run marginal cost capacity resource. For example, demand response would not be a candidate since its penetration could reach a saturation level given the limited base of interested end-users and the rising likelihood of deployment as increased DR penetration displaces generation capacity.

Second, the reference technology must have *demonstrated commercial interest by merchant developers*. While we are able to capture in our Net CONE analysis the majority of considerations made by new capacity developers in choosing which technologies to develop, we realize that there may be considerations that we cannot fully or properly quantify. To supplement our analysis for setting Net CONE, we find that it is necessary to observe the actual choices of capacity resource developers in developing projects to determine whether the technologies would likely be a part of the long-term resource mix. We rely on information available for projects recently completed, under construction, or in the interconnection queue in New England or the rest of the U.S.

Third, the reference technology must have an *estimated Net CONE that is not so high to make it implausible that the technology is part of the long-term equilibrium*. As different resource types provide different services other than capacity (e.g., baseload versus peaking operations), several technologies could be economic with the same Net CONE in a long-term equilibrium. However, market conditions are likely to be in disequilibrium at any given time, such that a single technology will have the lowest Net CONE value. For this reason, reference technologies that are clearly expected to be a part of the long-term mix of additions should not be excluded as a candidate reference technology, even if their Net CONE value may be temporarily slightly higher than other technologies. On the other hand, technologies with a much higher Net CONE are screened out due to the implausibility that they will be economic even in a long-term equilibrium.

The third principle is that the reference technology **Net CONE can be estimated with low uncertainty**. Estimating Net CONE values requires analyzing a large range of potential costs, revenues, and risks to develop a single value for each technology. We completed our analysis using the best information available to us, including publicly available information, confidential revenue data from ISO-NE, Sargent & Lundy's proprietary cost data, and input from the NEPOOL Markets Committee members. However, there are many subjective decisions in developing the Net CONE value and thus it is necessary to review whether the uncertainty in estimating the Net CONE is especially high for any of the reference technologies considered. In addition, as setting the administrative

Net CONE too low has been found to have significantly more adverse outcomes than setting the Net CONE too high, we are cautious in setting Net CONE on a reference technology that has a low estimated value but does not appear to be entering the market.

We established two criteria to determine whether a technology's Net CONE can be estimated with low uncertainty. First, the *cost estimates are based on established, standardized technologies*. Estimated capital and fixed O&M costs will be more accurate for technologies that have recently been developed into actual projects in significant quantities with standardized configurations. For such technologies, equipment pricing and labor requirements are more standardized, and data is more plentifully available for informing the administrative estimate of Net CONE.

Second, *the energy and ancillary services (E&AS) revenue offset must have low uncertainty relative to other technologies*. Estimating E&AS revenue offsets is an inherently uncertain part of the analysis. We chose to estimate the E&AS for each technology using a simple approach that relies on the revenue and cost data available for actual plants and widely used electricity futures for projecting those revenues forward to the commitment period. Resources that have a significantly higher level of uncertainty in calculating the Net CONE should be not set as the reference technology, given the consequences of estimation error for demand curve performance described in Section III.A above.

2. Additional Considerations in Selecting Reference Technologies

Applying the criteria outlined above can identify more than one suitable reference technology. This is related to the fact the multiple technologies may be economic in a long-term equilibrium, especially since the system needs a mix of resources with different capabilities and duty cycles. However, even markets that may be in a long-term equilibrium can have oscillating short-term disequilibria in which market conditions temporarily make one technology or another most economic, with a lower Net CONE. Thus, we considered the following additional concepts in setting the Net CONE in this study, which we believe ISO-NE should also consider in future demand curve reset processes to avoid unintentional under-procurement or over-procurement.

The first is not to switch back and forth to the technology with the lowest Net CONE in every auction. This would under-procure on average, since the long-term average administrative Net CONE would be less than the long-term average Net CONE of any individual technology.¹² Moreover, Net CONE fluctuations may reflect changes in estimation error as well as fundamentals, and chasing the downward errors would almost guarantee under-procurement. (Similarly, it does not make sense to always switch to the technology with the highest Net CONE.)

Maintaining a single reference technology over time can be expected to procure the right amount on average. However, doing so might lead to over-procurement when another technology has a lower Net CONE. A less obvious but more worrisome problem is that maintaining a single reference technology could lead to under-procurement when the reference technology temporarily has the lowest estimated Net CONE. This may occur if developers of the lowest Net CONE technology believe it will not always have the lowest

¹² Roy Shanker, *Discussion Paper—PJM Proposal to Base Net Cone of the Lower of the CC or CT Alternatives, on behalf of the PSEG Companies*.

Net CONE, with other technologies becoming more economic sometimes in the future; if so, future FCM prices may be below its own real-levelized Net CONE on average. Thus, in a long-term equilibrium characterized by oscillations between disequilibrium market conditions, the temporarily lowest Net CONE technology might enter at a price higher than its own level-real Net CONE.

To account for these dynamics, it may be preferable to set Net CONE at an *average* of the technology that is lowest and most likely to enter along with other technologies that are also likely to be part of the long-term equilibrium mix of entrants. The average provides a proxy for how entrants (typically the ones with lowest Net CONE) might incorporate their long-term view. If the weights on the averages stay the same over time, the capacity market will procure the right amount of capacity on average (as would maintaining a single reference technology). Setting Net CONE in this way can help stabilize resource adequacy through the expected short-term disequilibria and diversify the risk of estimation errors with any single technology.

However, we explain in Section XI.B the special conditions in New England that caused us to recommend a single technology (the CC) instead of averaging at this time.

3. Comparison to NYISO and PJM Reference Technology Approaches

The reference technology evaluation criteria and selection considerations we propose for ISO-NE differ from those used by other RTOs with capacity market demand curves. In those RTOs, the reference technology is selected based on quite specific requirements in their respective tariffs. NYISO's tariff requires that a "peaking unit" be used as the reference technology, which is defined as "the unit with the technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable."¹³ The PJM tariff requires the "reference resource" to be a "combustion turbine generating station, configured with two General Electric Frame 7FA turbines."¹⁴

We developed the criteria above to identify the reference technology that is most appropriate for the New England power system. Also, we included a combined-cycle gas turbine plant in our analysis even though it has not yet been selected as the reference technology in other regions. A recent review of the NYISO capacity market suggested that the CC technology be considered. While the review found no economic rationale for excluding the CC, it cautioned that potentially higher uncertainty in setting the E&AS revenue offset for the CC provides a reason to be cautious in selecting the CC as the reference technology.¹⁵

¹³ New York Independent System Operator, Inc., *Market Administration and Control Area Services Tariff*, FERC Docket #ER13-1380-000, Section 5.14.1.2, September 12, 2013.

¹⁴ PJM, *PJM Manual 18: PJM Capacity Market*, Revision: 20, p. 17.

¹⁵ Scott M. Harvey, William W. Hogan, and Susan L. Pope, *Evaluation of the New York Capacity Market*, March 5, 2013. Available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Final_New_York_Capacity_Report_3-13-2013.pdf.

D. Technology Screening

We developed Net CONE estimates for a set of technology types that passed an initial screen of the criteria we defined. The screen included a review of capacity resources against the criteria in Table 1 (other than a review of Net CONE, which we had not estimated yet). We reviewed each technology's ability to comply with all environmental regulations, its ability to be dispatched to generate whenever capacity is scarce, and its availability as a standardized, utility-scale commercial plant without inherent constraints on the amount that could enter.

1. Technologies Evaluated

Based on this initial screening, we identified three gas-fired technologies, and stakeholders requested a fourth gas-fired technology (LM6000), for developing Net CONE estimates:

- 2×0 F-class Frame Combustion Turbine (Frame CT)
- 2×1 Combined Cycle Gas Turbine (CC)
- 2×0 LMS100 Combustion Turbine (LMS100)
- 4×0 LM6000 Combustion Turbine (LM6000)

Our inclusion of the Frame CT with selective catalytic reduction (SCR) as a candidate reference technology is supported by the Commission's recent ruling in favor of NYISO's filing that the frame technology is, according to the terms in its tariff, "economically viable."¹⁶ In accordance with this ruling, we assume the Frame CT with an SCR is viable and can meet environmental regulations on nitrogen oxide (NO_x) emissions in New England.

Stakeholders brought to our attention additional issues with obtaining air permits for the Frame CT. Several generators noted that they do not believe a Frame CT would be able to receive an air permit due to its lower efficiency and higher greenhouse gas emissions rate relative to the aeroderivative turbine, citing conversations with the Massachusetts Department of Environmental Protection and the recent challenges Footprint Power had obtaining the air permit for its proposed combined-cycle plant at Salem Harbor. The generators also note that though Footprint Power has now received the permit, the risk of project delays might discourage the Frame CT from being built in New England. Through our own discussions with New England state environmental regulators and generators, we found no evidence of permits being refused (but also no requests for permits for this technology) nor existing rules that would preclude a Frame CT from obtaining a permit in the future. Thus, we do not believe that these claims amount to a reason for excluding the Frame CT as a candidate reference technology.

Another issue we reviewed for the Frame CT is the limited commercial interest by merchant developers in the technology in simple cycle operation. For the 2013 ORTP Study, we did not develop a Net CONE for the Frame CT due to the lack of commercial interest in New England. Only one 74 MW E-class frame turbine has been developed in simple-cycle mode since 2000. Broadening the view to other regions with capacity markets, there has

¹⁶ Federal Energy Regulatory Commission, Order Accepting Tariff Filing Subject to Condition and Denying Waiver. New York Independent System Operator, Inc. FERC Docket No. ER14-500-000, 146 FERC ¶ 61,043, Issued January 28, 2014. ("FERC NYISO Order")

been no merchant entry of a frame-type CT since 2009, with just a single non-merchant 160 MW turbine installed in PJM by Dominion at the Ladysmith plant. Nationally, 3,700 MW of frame-type CTs have been developed since 2009, and currently there are 2,000 MW in development. However, commercial development of the F-class frame turbine with an SCR (as required in New England) has been limited to the 800 MW NRG Marsh Landing plant in California that began operations in the 2013 under a PPA. We have not been able to identify any additional F-class frame turbines with an SCR in development.

The total amount of each technology considered that has been developed or is currently under development by region is shown in Table 2. Due to incomplete data availability, the table does not capture whether the entry occurred on a merchant or regulated basis, but we note that the CC and CT plants that have been installed in ISO-NE since 2009 are non-merchant. Most of that capacity entered in Connecticut was in response to two state-sponsored, PPA-backed solicitations (one CC and four CT plants), and one CT was built by a municipal utility in Massachusetts. On the contrary, the majority of the 1,331 MW of CC capacity in development in ISO-NE is from two proposed merchant plants; the Footprint Power Salem Harbor CC is included in this value.

Table 2
Capacity Installed and In Development in Different Regions Since 2000

Installed Since 2000 (MW)	ISO-NE	NYISO	PJM	U.S.
Combined Cycle	4,692	4,757	18,797	150,501
Simple Cycle	1,067	904	9,547	44,434
Aeroderivative Turbine	993	904	1,188	14,154
Frame Turbine	74	0	8,359	30,281
Installed Since 2009 (MW)	ISO-NE	NYISO	PJM	U.S.
Combined Cycle	622	1,452	2,530	29,119
Simple Cycle	706	462	764	10,075
Aeroderivative Turbine	706	462	604	6,351
Frame Turbine	0	0	160	3,724
In Development (MW)	ISO-NE	NYISO	PJM	U.S.
Combined Cycle	1,331	7,696	23,334	76,848
Simple Cycle	0	264	208	3,299
Aeroderivative Turbine	0	264	208	1,313
Frame Turbine	0	0	0	1,986

Source: Brattle analysis of data from Ventyx, *Energy Velocity Suite*, 2013. (Ventyx, 2013)
Data downloaded over May–November 2013.

Despite not being widely developed commercially, we chose to include the Frame CT as a candidate reference technology due to its use as the reference technology in other capacity regions and its lower turbine costs relative to the aeroderivative turbines (LMS100 and LM6000). We further address the implications of its limited development in our reference technology recommendation in Section X.

The CC should clearly be considered as a candidate reference technology, due to its commercial predominance over other technologies. We reviewed whether the plant should be based on a conventional plant design or a “flexible” design (*e.g.*, GE Flex60) that has recently been introduced to the market. Although the most recent plant under development in New England (Footprint Salem Harbor) is a flexible design, our review of the performance of the conventional packages versus the flexibility package found that the benefits of the improved flexible design are largely offset by its incremental costs, so the Net CONE calculation would likely be similar. However, there is limited data available for accurately calculating either the capital costs or the E&AS revenues of the flexible design due to its recent entry into the market. For these reasons, we assumed a conventional plant design for the CC. The full details of the CC configuration can be found in Section IV.

For aeroderivative CTs, we found no issues with environmental regulations or dispatchability. However, aeroderivatives are rarely developed on a merchant basis, and the total merchant and non-merchant capacity of aeroderivative CTs in development across the U.S is very limited (1.3 GW) compared to CCs (76.8 GW), as shown in Table 2 above. Comparing the LMS100 and LM6000, we initially chose the LMS100 because its performance characteristics are slightly better than the LM6000, and more LMS100s have been developed recently. For example, the ISO-NE interconnection queue currently lists just two CT projects, both of which employ the LMS100. We chose to complete an analysis of the LM6000 at stakeholder request since it is the turbine installed at the most recent CT plants located in New England (New Haven Harbor, Devon, and Middletown).

2. Technologies Not Evaluated

We screened out several technologies as candidate reference technologies, including demand-side resources, intermittent renewables, and oil-only units based on the principles and criteria listed in Table 1. By excluding these resources, we are not making any definitive statements on their viability or expectations for future market entry. The principles simply apply to our approach for identifying the reference technology for setting Net CONE in the FCM.¹⁷

Demand-side resources, such as Demand Response and Energy Efficiency were screened out as candidate reference technologies because they are not “available as standardized, utility-scale commercial plants without inherent constraints on the amount that could enter.” Demand resources are not standardized because their characteristics depend on the nature of the host load. This prevents identification of a representative type and size of

¹⁷ While several of these technologies were included in the 2013 ORTP Study, the objective of that study was different: provide a Net CONE value for each resource expected to have entry prices at the “low end of competitive entrants” that are below the FCA starting price. As our objective here is to identify which technologies represent the long-run marginal cost of supply, it is not necessary to include the same resources in our demand curve Net CONE analysis.

resource and would increase uncertainty in calculating the Net CONE.¹⁸ Moreover, demand-side resources may develop inherent constraints on entry as penetration reaches saturation. Finally, some demand resources' limitations on run hours decrease the confidence that demand-side resources would be available whenever capacity is scarce.

Wind and solar technologies are screened out because they are not dispatchable resources that can be called upon in hours when capacity is scarce. It is also unclear how "standardized" future wind and solar generation projects will be. For example, as wind development increases, additional wind capacity may occur in areas with lower capacity factors and increased interconnection costs. Finally, projecting prices for renewable energy credits (RECs) adds substantial uncertainty to the revenue offset and Net CONE estimates.

Oil-only CTs were suggested as a candidate reference technology by stakeholders. As shown in Section VIII, the existing combustion turbine plants that have been chosen as the representative units for calculating energy and ancillary services revenues operate primarily on oil. However, we specify in Section IV that they are dual-fuel units with interconnection to a gas pipeline due to the prevalence of such units in the existing fleet, and we found no recent interest in developing oil-only CTs in New England.

E. Estimating Net CONE for Candidate Reference Technologies

For the four candidate reference technologies, we conducted a bottom-up CONE estimate based on extensive data and reasonable assumptions about capital and O&M costs, trends in future revenues, the cost of capital corresponding to merchant entry, and an assumed economic life. We then estimated first-year E&AS revenues, which we subtracted from CONE to calculate Net CONE.

The remaining sections of the report provide details on how each component of Net CONE is developed for the candidate reference technologies.

We specify the technical specifications in Section IV for each technology based on our review of the characteristics of recent builds, environmental regulations, requirements for gas and electric interconnection, and operation requirements in New England.

The capital costs are developed in Section V by Sargent & Lundy through a bottom-up engineering approach based on the technical specifications. S&L uses proprietary cost data as well as publicly available sources to create costs for an expected competitive entrant. The fixed O&M costs are developed by S&L in a similar way in Section VI.

The CONE for each technology is calculated in Section VII based on the capital and fixed O&M costs and assumptions for the cost of capital, our view of long-term revenue trends, and the economic life.

The first year revenue offsets for each technology are developed in Section VIII based on historical E&AS margins of representative plants currently in operation and projections of their margins forward to the FCA9 commitment period based on electricity

¹⁸ As noted in an FTI Consulting report (see footnote 15), another conceptual concern with DR as the reference technology is that it would represent the last demand resource willing not to pay for capacity, instead of the marginal value of capacity to the load that remains at system peak conditions.

forward curves. We also consider the impact that the proposed Pay for Performance (PFP) market rules and the Peak Energy Rent (PER) deduction will have on revenue offsets based on the assumed scarcity hours during the first year of operation.

Based on our analysis of each component, we summarize the Net CONE results for the candidate reference technologies in Section IX and in Section X we recommend the reference technology and Net CONE value for ISO-NE's sloped demand curve for FCA9.

We screen changes in Net CONE for other capacity zones in New England in Section XI based on a review of differences in labor and land costs.

Finally, we provide in Section XII an approach for updating the Net CONE values for the candidate reference technologies in FCA10 and FCA11 based on updates to cost indices and futures data.

IV. TECHNICAL SPECIFICATIONS OF CANDIDATE TECHNOLOGIES

A. General Approach

We determined the technical specifications of each candidate reference technology primarily using a "revealed preferences" approach in which we consider the choices that developers have recently found to be most feasible and economic, as observed in recently constructed and planned units across the U.S. and in New England. However, because technologies and environmental regulations continue to evolve, we supplemented the actual observations based on our expertise and additional analysis of underlying economics, regulations, and infrastructure.

This study builds on the analysis we conducted for the 2013 ORTP Study. However, the objectives in this study differ, leading to some changes in assumptions. Whereas the ORTP objective was to estimate Net CONE "at the low end of competitive offers,"¹⁹ the demand curve requires estimating Net CONE as accurately as possible, with particular care not to understate the costs of likely entrants, as explained in Section III.A. We made the following changes accordingly: (a) we revised the assumed location of the new entrant plant to a location where labor costs were close to the regional average, with access to gas and electric infrastructure; (b) we assumed gas and electric interconnection needs are consistent with average recent new entrants; and (c) we reviewed all other components to determine any other necessary revisions.

B. Explanation of Key Assumptions

1. Location Selection

Plant location can affect environmental requirements (emissions controls and cooling), infrastructure availability, property costs and taxes, labor costs, available site characteristics, and plant performance. We found that environmental requirements were similar across New England and property costs and taxes are a relatively small component of

¹⁹ 2013 ORTP Study.

total plant costs, such that access to gas and electric infrastructure and labor rates were likely the main differentiator. Therefore, we focused on these factors to identify a location for an expected competitive entrant in the ROP capacity zone, as shown in Table 3.²⁰

Table 3
Labor Rates in Select New England Cities

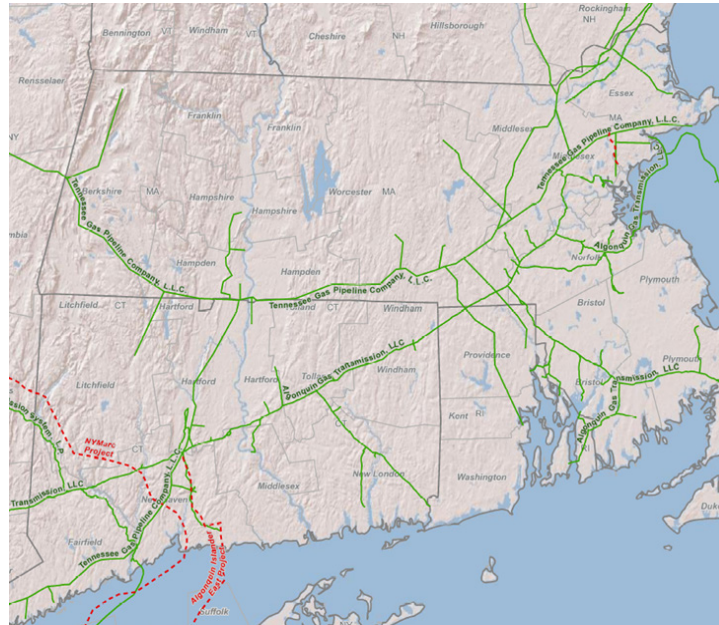
City	2013 Total Wage Rate Electricians	Productivity Factor	Labor Rate x Productivity Factor	Percent of ISO-NE Average	ISO-NE Zone
Stamford CT	\$86.48	1.30	\$112.42	168%	CT
Norwalk CT	\$82.59	1.30	\$107.37	160%	CT
Boston MA	\$75.61	1.30	\$98.29	147%	NEMA
Lawrence MA	\$70.50	1.15	\$81.08	121%	NEMA
Lowell MA	\$70.50	1.15	\$81.08	121%	NEMA
Hartford CT	\$59.22	1.30	\$76.99	115%	CT
New Britain CT	\$58.74	1.25	\$73.43	110%	CT
New Haven CT	\$58.74	1.25	\$73.43	110%	CT
Bristol CT	\$58.74	1.25	\$73.43	110%	CT
Meriden CT	\$58.74	1.25	\$73.43	110%	CT
Bridgeport CT	\$57.36	1.20	\$68.83	103%	CT
Danbury CT	\$57.36	1.20	\$68.83	103%	CT
Waterbury CT	\$57.36	1.20	\$68.83	103%	CT
Fitchburg MA	\$56.80	1.15	\$65.32	98%	ROP
Worcester MA	\$56.80	1.15	\$65.32	98%	ROP
Pawtucket RI	\$54.99	1.15	\$63.24	95%	ROP
Providence RI	\$54.99	1.15	\$63.24	95%	ROP
Woonsocket RI	\$54.99	1.15	\$63.24	95%	ROP
Brockton MA	\$54.86	1.15	\$63.09	94%	ROP
Fall River MA	\$54.86	1.10	\$60.35	90%	ROP
New Bedford MA	\$54.86	1.10	\$60.35	90%	ROP
Pittsfield MA	\$50.60	1.10	\$55.66	83%	ROP
Springfield MA	\$50.60	1.10	\$55.66	83%	ROP
Lewiston ME	\$43.24	1.15	\$49.73	74%	ME
Portland ME	\$43.24	1.15	\$49.73	74%	ME
Concord NH	\$43.00	1.15	\$49.45	74%	ROP
Manchester NH	\$43.00	1.15	\$49.45	74%	ROP
Nashua NH	\$43.00	1.15	\$49.45	74%	ROP
Bangor ME	\$41.71	1.15	\$47.97	72%	ME
Burlington VT	\$33.80	1.15	\$38.87	58%	ROP

Sources: S&L analysis of data from RS Means and 2014 Global Construction Costs Yearbook.

Our locational screening found Worcester County in Massachusetts to be representative of the ROP capacity zone for labor rates, with rates close to the average of New England cities for which data was available. We also found that Worcester County provides adequate access to high voltage transmission infrastructure and major gas pipelines, as shown in Figure 1 and Figure 2, respectively.

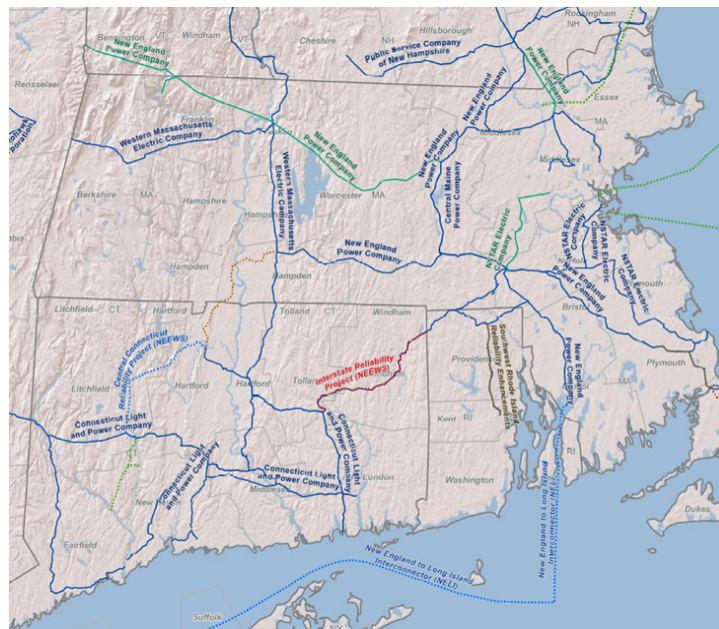
²⁰ We assessed labor costs using labor rates from the RS Means' Labor Rates for the Construction Industry reference book and productivity factors from 2014 Global Construction Costs Yearbook, published by Compass International, Inc. (See R.S. Means, *Labor Rates for the Construction Industry*, 2013, Reed Construction Data, 40th Ed.)

Figure 1
Major Gas Pipelines in Southern New England



Source: SNL, SNL Financial. Data downloaded over May–November 2013. (SNL, 2013)

Figure 2
Electric Transmission Systems in Southern New England



Source: SNL, 2013.

Import-constrained capacity zones in New England could have structurally higher costs than the ROP estimate. For this reason, the current import-constrained zones of Connecticut and Northeast Massachusetts/Boston (NEMA/Boston) were screened to determine whether these locations would need a separate Net CONE estimate. The cost screening effort is discussed in Section XI.

2. Site Conditions

We reviewed site conditions for Worcester County such as elevation, ambient conditions, and site characteristics for estimating the likely performance characteristics of the candidate reference technologies in the Rest of Pool capacity zone. Based on the generalized topography of the eastern portion of Massachusetts, the representative elevation for Worcester was estimated to be 450 feet above mean sea level. The ambient conditions were developed from Worcester, MA Regional Airport weather data and adjusted to the representative elevation.²¹ Three distinct conditions were evaluated: summer average, winter average, and ICAP. ICAP, or installed capacity, is established by ISO-NE for use in determining the Summer Qualified Capacity, which is used in our analysis to calculate all per-kilowatt values, including CONE. The representative weather data is shown in Table 4.

Table 4
Ambient Condition Assumptions for Worcester, MA

Ambient Conditions	Dry Bulb Temperature °F	Mean Co-incident		Relative Humidity %
		Wet Bulb Temperature °F		
Summer Average	70	64.2		73.6
Winter Average	29	24.0		45.8
ICAP	90	74.6		49.3

Sources: Summer and winter conditions developed by S&L based on data for Worcester Regional Airport from the National Climatic Data Center's Engineering Weather dataset. ICAP conditions provided by ISO-NE.

We assume the new entrant plant is developed at a greenfield location due to the generic nature of the reference resource and the potentially limited brownfield site availability. "Greenfield" in this case means there are no adjacent generating facilities, so common facilities that might otherwise be available at a brownfield site are included in the cost estimate (*e.g.*, switchyard, administration and control buildings, water tanks, waste water and sanitation infrastructure, fire water infrastructure, *etc.*). For brownfield sites, these common facilities would most likely have existed previously and require little or no modification. Brownfield sites can also involve additional costs, such as removing old structures and adapting the plant layout to the space available. Since brownfield facilities vary significantly from site to site, actual cost savings are difficult to predict with certainty.

Based on a review of the geological conditions and recent projects around Worcester County, we assumed that spread footing foundations are a reasonable construction design. Therefore, pile foundations are not required at this location.

²¹ Ambient condition data for Worcester Regional Airport developed from National Climatic Data Center, *Engineering Weather 2000 Interactive Edition*. Asheville, NC, 2000.

Adjustments were made for adapting the values to representative site elevation using J.V. Iribarne, and W.L. Godson, *Atmospheric Thermodynamics*, Second Edition. D. Reidel Publishing Company. Dordrecht, Holland, 1981.

3. Environmental Requirements and Implications

Emission control technology requirements for new major stationary sources are determined through the New Source Review (NSR) pre-construction permitting program. The NSR permitting program evaluates the quantity of regulated air pollutants the proposed facility has the potential to emit and determines the appropriate emission control technology/practice required for each air pollutant. The regulated air pollutants that have the most impact on emission control technology requirements for new combustion turbine (simple and combined-cycle) facilities are nitrogen oxides (NO_x) and carbon monoxide (CO).

NO_x and CO emissions from proposed gas-fired facilities located in New England are evaluated through two different types of NSR permitting requirements:

- Non-attainment NSR (NNSR) for NO_x emissions; and
- Prevention of Significant Deterioration (PSD) for CO emissions.

NO_x emissions are evaluated through the NNSR permitting requirements because NO_x (a precursor to ozone) is treated as a non-attainment air pollutant for all areas within the Ozone Transport Region (OTR), including New England, regardless of ozone attainment status.²²

New combustion turbine (simple and combined-cycle) facilities with no federally enforceable restrictions on operating hours (*i.e.*, may operate 8,760 hours per year) are deemed a major source of NO_x emissions and, therefore, trigger a Lowest Achievable Emission Rates (LAER) analysis to evaluate NO_x emission control technologies. The NO_x emission control technology required by the LAER analysis is likely to be a selective catalytic reduction (SCR) system. SCR systems are widely recognized as a viable technology on aeroderivative and smaller E-class frame combustion turbines and have more recently been demonstrated on F-class frame turbines. Our assumptions of an SCR on the F-class turbine is supported by the Commission's recent determination in approving the NYISO's assumption of F-class turbine with SCR as the proxy unit for its proposed Demand Curves that "the record of evidence presented in support of the frame unit with SCR is adequate in order to find that NYISO reasonably concluded that the F class frame with SCR is a viable technology."²³ In addition, we assume inlet air filters on all turbines and dry low NO_x burners on the CC and Frame CT are necessary to achieve the required emissions reductions.

CO emissions are evaluated through the PSD permitting requirements, because New England is designated as an attainment area for CO. New combustion turbine facilities with no operating hour restrictions will have potential-to-emit CO emissions in a quantity that exceeds the significant emission threshold for CO and, therefore, trigger a Best Available Control Technology (BACT) analysis to evaluate CO emission control technologies. The CO emission control technology required as a result of a BACT analysis is likely to be an oxidation catalyst (CO Catalyst) system.

²² The Ozone Transport Region (OTR) includes all of New England as well as Delaware, the District of Columbia, Maryland, New Jersey, New York, Pennsylvania, and portions of Virginia.

²³ FERC NYISO Order, at paragraph 58.

For these reasons, an SCR and a CO Catalyst system were assumed for all candidate reference technologies as the likely requirements resulting from the NSR permitting program for new gas-fired facilities proposed in New England.

4. Plant Configuration

Similar to the 2013 ORTP Study, we selected a 2×0 configuration for the LMS100 model to reduce the impact of common costs on a per-kilowatt basis, as well as for the Frame CT. For the smaller LM6000, we chose a 4×0 to provide some economies of scale and a similar quantity of output as the LMS100. We also found in our review of the plants bid into the recent Connecticut peaking capacity RFP that a configuration with 4 or more LM6000s is common.

For the CC, the Siemens SGT6-5000F(5) with a 2×1 configuration was selected as the candidate reference technology because of the number of recent projects using this turbine model and configuration. This is one of the most common configurations for CC plants built in the U.S. and New England since 2010 as indicated by Table 5 and Table 6.

Table 5
U.S. CC Plants Under Construction or Built Since 2010

	< 300 <i>(MW)</i>	300-500 <i>(MW)</i>	500-700 <i>(MW)</i>	700-900 <i>(MW)</i>	900-1100 <i>(MW)</i>	1100-1300 <i>(MW)</i>	> 1300 <i>(MW)</i>	Total <i>(MW)</i>
2 × 1	762	1,732	12,064	4,856	0	0	0	19,414
2 × 2	0	0	560	0	0	0	0	560
3 × 1	170	0	545	880	950	4,969	0	7,514
Total	931	1,732	13,169	5,736	950	4,969	0	27,487

Source: Ventyx, 2013.

Table 6
Turbine Models of U.S. CC Plants Since 2010

Turbine Model	ISO-NE		U.S.		Avg. Plant Size (MW)
	(MW)	(count)	(MW)	(count)	
General Electric Co-MS7001FA GT	0	0	4,317	7	617
Mitsubishi Heavy Industries-M501G	0	0	3,751	4	938
Siemens Power Generation Inc-SGT6-5000F	620	1	3,334	6	556
General Electric Co-PG7241(FA)	0	0	972	2	486
General Electric Co-MS7001EA	0	0	864	4	216
Siemens Power Generation Inc-SCC6-5000F	0	0	809	1	809
Siemens Power Generation Inc-Flex-Plant 30	0	0	809	1	809
Siemens AG-501G	0	0	695	1	695
Siemens Power Generation Inc-501FD	0	0	620	1	620
Siemens Power Generation Inc-V84.2	0	0	545	1	545
Siemens AG-501F	0	0	544	1	544
General Electric Co-S107H	0	0	366	1	366
General Electric Co-LM6000PC Sprint	0	0	308	1	308
General Electric Co-MS7001FA CC	0	0	290	1	290
General Electric Co-GE LM6000	0	0	200	2	100
General Electric Co-PGS6001B Frame 6B	0	0	46	1	46

Sources and Notes: Ventyx, 2013. This database is not comprehensive in identifying all turbine models, with approximately 60% of the total MW installed since 2010 being identified by turbine model type in the database.

In this configuration, the summer net capacity of the CC reference technology is 617 MW prior to the addition of duct firing, which is within the most common capacity range in Table 5. The addition of duct firing, explained further below, increases the summer net capacity to 715 MW.

5. Fuel Assumptions

Dual-fuel capability plants can run with natural gas or liquid fuel (primarily ultra-low sulfur diesel, or ULSD) as its fuel source. Dual-fuel capability allows plants to continue operation during times of gas interruption, such as during periods of gas curtailment events, and on short notice, unless “no-notice” service has been arranged with the gas distributor. Ensuring enough guaranteed fuel supply to meet reliability objectives during cold snaps is a major concern for ISO-NE. ISO-NE sponsored a separate analysis which indicated that the proposed Pay for Performance (PFP) incentives would justify the costs of dual-fuel capability.²⁴ Therefore, we assume dual-fuel capability for all reference plants.

To be capable of firing gaseous and liquid fuels, the plants are assumed to be equipped with enough liquid fuel storage and infrastructure on-site for three days of continuous operation. Dual-fuel capability also requires the combustion turbines to have water injection installed to reduce NO_x emissions while firing liquid fuel. These

²⁴ Todd Schatzki and Paul Hibbard, *Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives*, September 2013. Available at: http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/a3b_analysis_group_fcm_pi_impact_assessment_report_09_2013.pdf

modifications as well as the costs associated with fuel oil testing, commissioning, inventory, and the capital carrying charges on the additional capital costs contribute to the overall costs for dual-fuel capability. The incremental cost is about \$17.5 million (in 2013 dollars) for the CC, which includes equipment, labor, materials, indirect costs, and fuel inventory, and contributes approximately \$0.5/kW-month to the Net CONE.

Some types of combustion turbines need gas compression, depending on the fuel gas delivery pressure requirements specified by the combustion turbine vendors. In general, the frame machines operate at lower fuel gas pressures than the aeroderivative machines. As such, the frame machines utilizing the Siemens SGT6-5000(F) models in both simple and combined-cycle configurations are assumed to not require gas compression. The aeroderivative configurations utilizing the GE LMS100 and LM6000 models, however, are assumed to require gas compression to meet the relatively higher fuel gas delivery pressure requirements, which adds \$5 million to the capital costs.

6. Cooling System

Dry cooling systems use air instead of water to cool the steam exiting the steam turbine in a combined-cycle configuration or the intercooler for the GE LMS100 turbine. Therefore, dry cooling avoids violating pending environmental regulations by greatly minimizing the amount of water withdrawn from natural resources. In addition, according to the EIA-860 Database, the majority of the cooling water systems installed in the past 15 years at electric generating facilities in Massachusetts have been dry (air) cooling systems, which presents evidence of the regulators' revealed preference. The tradeoffs to these water savings are higher capital costs and lower efficiencies, which means more fuel is needed per unit of electricity. Dry cooling adds approximately \$50 million in capital costs to the CC, including equipment and associated labor and other EPC cost increases.

7. Supplemental Firing

In a combined-cycle configuration, supplemental firing of the steam generator, also known as duct firing, increases steam production and hence increases the output of the steam turbine. Existing CC plants in New England, such as Kleen, Mystic, and Fore River, have duct firing.²⁵

There is no standard optimized design for supplemental firing. Each unit is unique, and the decision to incorporate supplemental firing with the plant configuration and the amount of firing is dependent on the owner's preference and perceived economic value. As part of this evaluation, duct firing was applied as a constant heat input to the duct burners for 98 MW of additional plant output, which is consistent with the duct firing capability of CC plants constructed since 2012 or in development in New England, as shown in Table 7.

²⁵ Ventyx, 2013.

Table 7
Duct-Firing Capability of CC Plants Constructed Since 2010 and In Development

	Installed Capacity	No. of Plants	Avg. Plant Size	Avg. Duct Fired Capacity	Duct Fired Addition %
	<i>(MW)</i>	<i>(count)</i>	<i>(MW)</i>	<i>(MW)</i>	<i>(%)</i>
ISO-NE	620	1	620	100	19%
U.S.	9,868	13	759	85	13%

Sources and Notes: Duct firing capacities for CC plants with duct firing capability compiled by Ventyx, 2013.

Including duct-firing capabilities increases the net capacity of the plant, but will reduce efficiency and increase heat rate due to the higher incremental heat rate of the supplemental firing and the reduced efficiency of steam turbine when not operating at full output. We included these factors in our calculation of net summer plant capacity and net heat rate shown below in Table 8 and Table 9.²⁶

8. Evaporative Cooling

Evaporative coolers are installed downstream of the filtration system to lower the combustion turbine inlet air temperature during warm weather operation and increase turbine output and efficiency. The performances in this study assume evaporative coolers are installed and operating during summer and ICAP conditions. In addition, the combustion turbines in both simple and combined-cycle arrangements are equipped with an inlet filtration system to protect from airborne dirt and particles. Evaporative coolers add \$3 million per combustion turbine to the capital costs.

9. Electrical Interconnection

A 200–700 MW generating station would most likely be installed on the 345 kV transmission grid in New England. We assumed that the switchyard (including generator circuit breakers, main power and auxiliary generator step-up (GSU) transformers, and switchgear) within the plant boundary is included as an EPC cost under “Other Equipment.” We assume the plant would be connected via a half-mile overhead transmission line to a 345 kV open-air substation that will require upgrades, as explained further in the next section. The generator lead and substation upgrades are included separately as Owner’s Costs. As the network upgrade costs per kW of capacity show no correlation to plant size, we adopted the reasonable assumption that generic future projects of different size expect to pay the same

²⁶ The incremental heat rate of duct firing is comparable to that of a simple-cycle combustion turbine. Hence, supplemental firing is often considered similar to peaking duty. The steam turbine-generator and associated equipment in a combined-cycle configuration with supplemental firing will be designed and purchased for the full steam load capability, but may not operate at these design conditions most of the time. Operating such a plant with little or no supplemental firing is therefore at a less than optimum point for the steam turbine and results in poorer heat rates than a plant sized without supplemental firing and operated close to its optimum point.

amount on a per-kW basis, plus the cost of a half-mile overhead 345 kV line from the new generating plant.

C. Summary of Specifications for Each Candidate Reference Technology

1. Technical Specifications

Based on the assumptions discussed above, the technical specifications for each candidate reference technology are shown in Table 8. Net plant capacity and heat rate are calculated at 90°F dry bulb temperature, which is established by ISO-NE for use in determining the Summer Qualified Capacity.

Table 8
Summary of Candidate Reference Technology Technical Specifications

Unit Specifications	LM6000 Combustion Turbine	LMS100 Combustion Turbine	F-Class Frame Combustion Turbine	Combined Cycle Gas Turbine
Turbine Model	GE LM6000 PC SPRINT	GE LMS100 PA	Siemens SGT6-5000F(5)	Siemens SGT6-5000F(5)
Configuration	4 x 0	2 x 0	2 x 0	2 x 2 x 1
Net Summer Plant Capacity (MW)	173	188	417	715
without Duct Firing (MW)	-	-	---	617
Cooling System	N/A	Dry Fin-Fan Intercooler	N/A	Dry
Power Augmentation	Evaporative Cooling No inlet chillers	Evaporative Cooling No inlet chillers	Evaporative Cooling No inlet chillers	Evaporative Cooling No inlet chillers
Net Summer Heat Rate (Btu/kWh,HHV)	9,738	9,089	10,577	7,437
without Duct Firing (Btu/kWh,HHV)	---	---	---	7,128
Environmental Controls	Water Injection NOx Control Inlet Air Filters SCR with Tempering Air System CO Catalyst	Water Injection NOx Control Inlet Air Filters SCR CO Catalyst	Dry Low NOx Burners Water Injection NOx Control Inlet Air Filters SCR with Tempering Air System CO Catalyst	Dry Low NOx Burners Water Injection NOx Control Inlet Air Filters SCR CO Catalyst
Dual Fuel Capability	ULSD	ULSD	ULSD	ULSD
Blackstart Capability	No	No	No	No
On-Site Gas Compression	Yes	Yes	No	No
Interconnection	345 kV	345 kV	345 kV	345 kV
Plot Size (acres)	13	10	10	20
Location	Worcester, MA	Worcester, MA	Worcester, MA	Worcester, MA

2. Performance and Operating Capabilities

Based on the technical specifications outlined above, we estimated more detailed performance and operating capabilities for the reference technologies across several different ambient conditions for Worcester, MA. Table 9 provides the net plant capacity, net heat rate, potential-to-emit NO_x and CO, ramp rate, minimum up and down times, and the forced outage rate. While the net plant capacity is the only value directly used for calculating Net CONE, the operating characteristics of the combustion turbines are important for determining the E&AS revenues (see Section VIII).

Table 9
Summary of Candidate Reference Technology Performance Capabilities

Plant Performance	F-Class Frame Combustion Turbine	Combined Cycle Gas Turbine	LM6000 Combustion Turbine	LMS100 Combustion Turbine
Net Plant Power Rating ¹				
29 °F, 50.7% RH	450 MW	754 MW	192 MW	202 MW
70 °F, 73.8% RH	431 MW	741 MW	182 MW	204 MW
90 °F, 49.6% RH	417 MW	715 MW	173 MW	188 MW
Net Plant Heat Rate (HHV) ¹				
29 °F, 50.7% RH	10,383 Btu/kWh	7,405 Btu/kWh	9,665 Btu/kWh	9,041 Btu/kWh
70 °F, 73.8% RH	10,770 Btu/kWh	7,469 Btu/kWh	9,810 Btu/kWh	9,136 Btu/kWh
90 °F, 49.6% RH	10,806 Btu/kWh	7,543 Btu/kWh	9,872 Btu/kWh	9,260 Btu/kWh
Ramp Rate	30 MW/Min	30 MW/Min (CT)	30 MW/Min	50 MW/Min
MW from 0-10 min	~70% Load	~70% Load ²	100% Load	100% Load
MW from 0-30 min	100% Load	100% Load ²	100% Load	100% Load
Minimum Up Time	1 hr	4 hr	1 hr	1 hr
Minimum Down Time	1 hr	4 hr	1 hr	1 hr
Forced Outage Rate	2.0%	2.5%	2.0%	2.0%

Sources and Notes: S&L analysis. (1) Net plant power rating and net heat rate are for average degraded conditions and firing natural gas. CC is based on duct firing operations at a constant 470 MMBtu/hr (HHV) to the duct burner, per HRSG. (2) Conservatively based only on CT portion; some contribution could be expected from steam turbine, particularly on hot starts.

V. CAPITAL COSTS

Overnight capital costs were estimated for each reference technology, as shown in Table 13 below. Capital costs are divided into the engineering, procurement, and construction (EPC) costs, such as major equipment, labor, and materials, and non-EPC or owner's costs, such as development costs, interconnection costs, and fuel inventories.

All equipment and material costs are initially estimated in 2013 dollars based on S&L proprietary data, vendor catalogs, or publications. Labor rates, developed based on union craft rates in 2013, and material costs have both been estimated for Worcester, Massachusetts.²⁷ Estimates for the number of labor hours and quantities of material and equipment needed to construct simple and combined-cycle plants are based on S&L experience on similarly sized and configured facilities.

We estimate the overnight capital cost in 2018 dollars by escalating the 2013 cost data to the middle of the construction period using component-specific escalation rates and then further adjusting for inflation to the end of the construction period. The 2018 "installed cost" is the present value of the construction period cash flows as of the end of the construction period and is calculated using a monthly drawdown schedule and the estimated cost of capital for the project.

²⁷ Costs have been added to cover FICA, fringe benefits, workmen's compensation, small tools, construction equipment, and contractor site overheads. Work is assumed to be performed on a 50-hour work week by qualified craft labor available in the plant area. An allowance to attract and keep labor was included and a labor productivity adjustment was applied.

A. EPC Costs

Costs that are typically within the scope of an EPC contract include the major equipment (gas turbines, heat recovery steam generator (HRSG), condenser, and steam turbine), other equipment, construction and other labor, materials, sales tax, contractor's fee, and contractor's contingency. The contracting scheme for procuring professional EPC services in the U.S. is customarily implemented with a single contractor and a single, fixed, lump-sum price. A single contract reduces the owner's responsibility with construction coordination and reduces the potential for missed or duplicated scope compared to multiple contract schemes. The estimates and contractor fees herein reflect this contracting arrangement.

1. Equipment and Sales Tax

"Major equipment" includes costs associated with the gas turbines, HRSG, SCR, condenser, and steam turbines, where applicable. "Other equipment" includes inside-the-fence equipment required for interconnection and other miscellaneous equipment and associated freight costs. Equipment costs, including the combustion turbine costs, are based on S&L's proprietary database and continuous interaction with clients and vendors regarding equipment costs and budget estimates. A sales tax rate of 6.25% is applied to the sum of major equipment and other equipment to account for the sales tax on all equipment.²⁸

2. Labor and Materials

Labor consists of "construction labor" associated with the EPC scope of work and "other labor," which includes engineering, procurement, and project services as well as construction management, field engineering, start-up, and commissioning services. Materials include all construction material associated with the EPC scope of work, material freight costs, and consumables during construction.

3. EPC Contractor Fee and Contingency

The EPC contractor fee is added compensation and profit paid to an EPC contractor for coordination of engineering, procurement, project services, construction management, field engineering, and startup and commissioning. Our capital cost estimates include an EPC contractor fee of 10% and 12% of EPC costs for simple-cycle and combined-cycle facilities, respectively.

Contingency covers undefined variables in both scope definition and pricing that are encountered during project implementation. Examples include nominal adjustments to material quantities in accordance with the final design; items clearly required by the initial design parameters that were overlooked in the original estimate detail; and pricing fluctuations for materials and equipment. Our capital cost estimates include an EPC contingency of 10% of EPC costs and fees.

The EPC contractor fee and the contingency are based on S&L's proprietary project cost database.

²⁸ 6.25% state sales tax can be found on Massachusetts Department of Revenue website: <http://www.mass.gov/dor/individuals/taxpayer-help-and-resources/tax-guides/salesuse-tax-guide.html>.

B. Owner's Capital Costs

Owner's costs include the costs not expected to be included in the EPC contract, including development costs, legal fees, gas and electric interconnections, and fuel inventories.

1. Owner's Cost (Services)

Owner's costs include items such as development costs, oversight, legal fees, emissions reductions credits, startup and testing, and training. We assume owner's costs are 6% of the total EPC costs. This is based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

2. Gas Interconnection

We estimated gas interconnection costs based on cost data for gas lateral projects similar to the interconnection of a greenfield plant.²⁹ The summary of project costs and the average per-mile pipeline and metering station costs are shown in Table 10. We assume gas interconnection will require a metering station and a two-mile lateral connection, based on a high-level review of the location of gas plants in New England relative to gas pipelines. From this data, we estimate that gas interconnection costs will be \$10.5 million (in 2013 dollars) for all plants, as we found no relationship between pipeline width and per-mile costs in the project cost data.

Table 10
Gas Interconnection Costs

Gas Lateral Projects	State	In-Service Year	Pipeline Width inches	Pipeline Length miles	Pipeline Cost 2013\$	Pipeline Cost 2013\$/mile	Meter Station Y/N	Meter Station Cost 2013m\$
New England Projects								
Algonquin Kleen Energy Lateral	CT	2009	20	1.1	\$6,929,918	\$6.1	Y	\$1.8
Algonquin Cape Cod Lateral	MA	2007	18	3.5	\$14,851,022	\$4.2	Y	\$2.8
U.S. Projects								
Carty Lateral Project	OR	2014	20	24.3	\$51,310,471	\$2.1	Y	\$2.3
South Seattle Delivery Lateral Expansion	WA	2013	16	4.0	\$13,597,000	\$3.4	N	n.a.
Bayonne Delivery Lateral Project	NJ	2012	20	6.2	\$13,698,507	\$2.2	Y	\$3.8
North Seattle Delivery Lateral Expansion	WA	2012	20	2.2	\$11,628,508	\$5.3	Y	\$1.4
FGT Mobile Bay Lateral Expansion	AL	2011	24	8.8	\$27,788,565	\$3.1	Y	\$2.5
Northeastern Tennessee Project	VA	2011	24	28.1	\$131,879,745	\$4.7	Y	\$2.9
Hot Spring Lateral Project	TX,AR	2011	16	8.4	\$33,786,739	\$4.0	Y	\$3.8
Average						\$3.9		\$2.7

Sources and Notes Recent gas lateral projects were identified based on an EIA dataset (<http://www.eia.gov/naturalgas/data.cfm>), and detailed cost information was obtained from each project's application with FERC, which can be retrieved from the project's FERC docket (available at http://elibrary.ferc.gov/idmws/docket_search.asp).

²⁹ The gas lateral projects were identified from the EIA's "U.S. natural gas pipeline projects" database available at <http://www.eia.gov/naturalgas/data.cfm>. The detailed costs are from each project's FERC application, which can be found by searching for the project's docket at http://elibrary.ferc.gov/idmws/docket_search.asp.

3. Electric Interconnection

Electrical interconnection costs are based on our review of transmission costs reported in Section 15.5 Applications provided by ISO-NE staff, as shown in Table 11. The costs reported in the Section 15.5 applications as “pool transmission facilities” (PTF) include all interconnection costs beyond the generator lead.³⁰ The average historical cost of upgrades beyond the generator lead was \$35/kW (2013 dollars).

Table 11
Electric Interconnection Costs

<i>Project</i>	<i>Summer Capability MW</i>	<i>PTF Costs 2013\$</i>	<i>PTF Costs 2013\$/kW</i>
Historic Data from 15.5 Applications			
Bucksport	157	264,385	2
Westbrook	523	17,703,195	34
Rumford Power	245	21,264,979	87
Maine Independence	490	29,602,411	60
Androscoggin Energy	128	3,050,416	24
Newington Energy	521	1,478,685	3
Lake Road	726	20,458,743	28
Milford Power	485	12,237,377	25
Berkshire Power	236	9,954,560	42
AES Granite Ridge	662	37,456,491	57
ANP Bellingham	466	8,964,340	19
ANP Blackstone	441	24,582,786	56
RISE	516	4,992,490	10
Fore River	683	22,644,863	33
Mystic 8 & 9	1,396	57,578,223	41
Kendall	154	3,050,094	20
Total	7,827	275,284,036	35
Expected Costs for Future Projects (assuming same cost per KW)			
LM6000	173	6,100,000	35
LMS100	188	6,600,000	35
Frame CT	417	14,700,000	35
CC	715	25,100,000	35

Source: The NEPOOL Transmission Facilities 15.5 Applications can be found on the ISO-NE website under the Reliability Committee Meeting Materials generally for the Reliability Committee meeting within a month of the 15.5 Application Date.

³⁰ The NEPOOL Transmission Facilities 15.5 Applications can be found on the ISO-NE website under the Reliability Committee Meeting Materials generally for the Reliability Committee meeting within a month of the 15.5 Application Date. Available at http://www.iso-ne.com/committees/comm_wkgrps/relbty_comm/relbty/mtrls/index.html.

In addition to the upgrade costs shown in Table 11, we assumed a half-mile transmission interconnection line is required, at a cost of \$1.1 million (in 2013 dollars) based on the costs of recent projects with similar terrain and conditions.

4. Financing Fees

Financing fees are the cost of acquiring debt financing, including associated financial advisory and legal fees. Financing fees are considered part of the plant overnight costs, whereas interest costs and equity costs during construction are also part of the total capital investment cost, or “installed costs,” but not part of the overnight costs. We assume financing costs are 4% of the EPC and non-EPC costs financed by debt, which is typical of recent projects.

5. Working Capital and Fuel Inventory

Working capital and inventories refer to the initial inventories of fuel, consumables, and spare parts that are normally capitalized. It also includes cash for the payment of monthly operating expenses. We assume non-fuel working capital is 1% of EPC costs based on S&L’s review of similar projects for which it has detailed information on actual owner’s costs.

We calculated the cost of the fuel inventory assuming a three day supply of ultra-low sulfur diesel fuel will be purchased prior to operation at a cost of \$2.80/gallon, or \$20/MMBtu (in 2013 dollars), based on current fuel prices.³¹ The present value of the fuel inventory that remains after 20 years (at the end of the assumed economic life) has been subtracted from the initial cost of the fuel.

6. Owner’s Contingency

Owner’s contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, longer length than assumed for gas lateral, greater than expected startup duration, *etc.* We assumed an owner’s contingency of 9% of Owner’s Costs based on S&L’s review of similar projects for which it has detailed information on actual owner’s costs.

C. Escalation to 2018 Overnight and Installed Costs

We escalated the components of the overnight capital cost estimates from 2013 to 2018 on the basis of cost escalation indices particular to each cost category. We estimated real escalation rates based on long-term (approximately 20-year) historical trends relative to the general inflation rate for equipment and materials, labor, and fuel inventories. The real escalation rate for each cost category was then added to the assumed inflation rate of 2.25% to determine the nominal escalation rates, as shown in Table 12.

³¹ Energy Information Administration, *Electric Power Monthly with Data for October 2013*, December, 2013. Available at: http://www.eia.gov/electricity/monthly/current_year/december2013.pdf.

Table 12
Capital Cost Escalation Rates

Capital Cost Component	Real Escalation Rate	Nominal Escalation Rate
Equipment and Materials	0.40%	2.65%
Labor	1.50%	3.75%
Fuel Inventories	-1.10%	1.15%

Sources: The equipment and materials and labor escalation rates are derived from the relevant BLS Producer Price Index and the fuel inventories escalation rate is derived from the EIA 2013 Annual Energy Outlook.

To more accurately reflect the timing of the costs a developer accrues during the construction period, we escalate the 2013 overnight capital cost line items to the middle of the construction period based on the escalation rate of each cost category. We then calculate the 2018 overnight capital costs by further escalating the total value by the inflation rate to the end of the construction period in 2018.

The 2018 installed costs are higher than the 2018 overnight capital costs since installed costs are the present value of construction costs, including the cost of capital during construction. The 2018 installed cost is calculated by first applying the monthly construction drawdown schedule for the project to the value escalated to the middle of the construction period and then finding the present value of the cash flows as of the end of the construction period using the assumed cost of capital as the discount rate.³²

D. Summary of Capital Costs

A summary of the capital costs for each candidate reference technology in 2013 dollars is shown in Table 13.

³² For the simple-cycle frame and aeroderivative turbines, the construction drawdown schedule occurs over 20 months with 80% of the costs incurred in the final 11 months prior to commercial operation. For the combine-cycle cases, the construction drawdown schedule occurs over 36 months with 80% of the costs incurred in the final 20 months prior to commercial operation.

Table 13
Summary of Capital Costs for Candidate Reference Technologies

Capital Costs	Units	LM6000	LMS100	F-Class Frame	Combined
		Combustion Turbine 173 MW	Combustion Turbine 188 MW	Combustion Turbine 417 MW	Cycle Gas Turbine 715 MW
EPC Costs					
Equipment					
Gas Turbines	2013\$	86,000,000	77,500,000	90,000,000	90,000,000
HRS / SCR	2013\$	21,600,000	14,000,000	17,100,000	43,000,000
Condenser	2013\$	-	-	-	26,900,000
Steam Turbines	2013\$	-	-	-	36,000,000
Other Equipment	2013\$	23,561,000	29,013,000	22,056,000	50,093,000
Construction Labor	2013\$	43,964,000	42,005,016	55,988,000	167,685,000
Other Labor	2013\$	13,172,000	14,566,103	15,457,000	37,994,000
Materials	2013\$	7,708,000	7,028,529	8,078,000	33,300,000
Sales Tax	2013\$	8,679,000	7,971,000	8,577,000	17,456,000
EPC Contractor Fee	2013\$	20,468,000	19,208,000	21,726,000	60,291,000
EPC Contingency	2013\$	22,515,000	21,129,000	23,898,000	56,272,000
Total EPC Costs	2013\$	247,667,000	232,421,000	262,880,000	618,991,000
Non-EPC Costs					
Owner's Costs (Services)	2013\$	14,860,000	13,945,000	15,773,000	37,139,000
Electrical Interconnection	2013\$	7,200,000	7,700,000	15,800,000	26,200,000
Gas Interconnection	2013\$	10,500,000	10,500,000	10,500,000	10,500,000
Land	2013\$	-	-	-	-
Fuel Inventories	2013\$	2,426,000	2,458,000	6,346,000	7,339,000
Working Capital	2013\$	2,477,000	2,324,000	2,629,000	6,190,000
Owner's Contingency	2013\$	3,372,000	3,323,000	4,594,000	7,863,000
Financing Fees	2013\$	6,924,000	6,544,000	7,645,000	17,141,000
Total Non-EPC Costs	2013\$	47,759,000	46,794,000	63,287,000	112,372,000
Total Capital Costs	2013\$	295,426,000	279,215,000	326,167,000	731,363,000
Overnight Costs	2013\$/kW	1,708	1,486	783	1,023
Overnight Costs	2018\$/kW	1,965	1,711	902	1,178
Installed Costs	2018\$/kW	2,033	1,771	933	1,258

Source: S&L and Brattle analysis.

Based on stakeholder requests, we compared our aeroderivative CT cost estimates to the actual costs of the projects reviewed in the Connecticut Department of Public Utilities peaker solicitation in 2008. At that time, a bid for one single-unit LMS100 project was received for \$1,449/kW, and seven bids for LM6000 projects ranging from two to ten units were received for \$1,046/kW to \$1,292/kW. These costs are much lower than those shown in the above table for the LM6000.

A direct comparison of the 2008 project bids to our estimates is complex because the assumptions for this CONE study are different. The 2008 projects utilized brownfield sites. Many of the projects had greater economies of scale because six, eight, or ten units were proposed. We expect that significant discounting of equipment prices was offered for such large orders of turbines, but do not have any data on the extent of price discounts. Other factors adding to the complexity include escalation of costs from 2008 to 2013 dollars, differences in equipment configuration (e.g., use of chillers), gas and electrical

interconnection costs, and lack of detail on owners cost, fuel inventory, spare parts, working capital, financing fees, and other items included in our CONE estimates.

In our view, the biggest reasons for the lower costs of the aeroderivative projects in the 2008 Connecticut peaker solicitation are economies of scale, escalation, brownfield site conditions, and items for which no detail was available, particularly equipment price discounts. After allowing for these differences, we found our CONE estimates were slightly higher and consequently made adjustments to some of our estimates of soft costs based on judgment and calibration. The above table reflects all adjustments we made to CONE estimates based on this review and other stakeholder comments.³³

VI. OPERATING AND MAINTENANCE COSTS

Fixed and variable O&M costs were estimated for each candidate reference technology, as shown in Table 14 below. The estimates were categorized according to fixed components (labor, materials and contract services, property taxes, insurance, and administrative and general) and variable components (major maintenance and consumables, waste disposal, and other O&M).

All O&M costs are initially estimated in 2013 dollars. We then estimate the O&M costs in 2018 dollars by escalating the cost data forward using the escalation rates in Table 12.

A. Fixed O&M

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance).

- **Plant Operation and Maintenance:** We estimated the labor, materials, and G&A costs based on a variety of sources, including the Electric Power Research Institute (EPRI) State-of-the-Art Power Plant Combustion Turbine Workstation v 9.0 data for existing plants reported on FERC Form 1, confidential data from other operating plants, and vendor publications for equipment maintenance.
- **Land Lease:** Although land costs are often considered a capital cost, current plant developers are likely to lease the land and thus consider the costs as fixed O&M. Leasing costs of \$19,000/acre-year were estimated from recent listings for industrial real estate in Massachusetts that ranged from approximately \$1,000/acre-year to \$25,000/acre-year. Considering the need for proximity to gas and transmission interconnection, a value at the high end of the range was selected. The leasing rate was multiplied by the estimated land requirement of 10

³³ If we adopted the actual reported costs of the recent aeroderivative projects in Connecticut as representative of LM6000s, their CONE would be \$15/kW-month. Net CONE would be \$14/kW-month, still \$3/kW-month higher than the CC Net CONE, assuming the fixed O&M and E&AS margins we estimated in Sections VI and VIII, respectively.

acres for the 2-unit simple-cycle plants, 13 acres for the 4-unit simple-cycle plant, and 20 acres for the combined-cycle plants.

- **Property Taxes:** The property tax rate of 0.75% of the overnight capital and site leasing costs per year was estimated from a sample of independent power projects in New England that have entered into agreements with local jurisdictions for payments in lieu of taxes (PILOT) based on common practice in the industry. In Worcester and Middlesex Counties, Massachusetts, commercial and industrial property tax rates typically range from about \$15 to \$30 per \$1,000 of assessed value (or 1.50% to 3.00%). Projects with PILOT agreements typically have rates between 0.25% to 1.00%, assuming a new plant and no change in assessed valuation over the term of the agreement.
- **Insurance:** We calculated insurance cost at 0.6% of the overnight capital cost per year, based on a sample of independent power projects recently under development in the Northeastern U.S. and discussions with a project developer.

B. Variable O&M

In our Net CONE analysis, the variable O&M costs shown in Table 14 are used in calculating the E&AS margins for each reference technology in Section VIII. We provide an explanation of the costs here to clearly differentiate which O&M costs are considered fixed and which are variable.

- **Major Maintenance:** Over the long-term operating life of a peaking facility, the largest component of variable O&M is the allowance for major maintenance expenses. Each major maintenance cycle for a combustion turbine typically includes regular combustion inspections, periodic hot gas path inspections, and one major overhaul. Since major maintenance activities and costs are spaced irregularly over the long-term, the cost in a given year represents an annual accrual for future major maintenance. For hours-based major maintenance, the average variable O&M cost (\$/MWh) is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored operating hours between overhauls, divided by the unit capacity in megawatts. For starts-based major maintenance, the average variable O&M cost (\$/factored start, per turbine) is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored starts between overhauls.
- **Other Variable O&M:** Other variable O&M costs are directly proportional to plant generating output, such as SCR catalyst and ammonia, CO oxidation catalyst, water, and other chemicals and consumables. These items are always expressed in \$/MWh, regardless of whether the maintenance component is hours-based or starts-based.

C. Escalation to 2018 O&M Costs

We escalated the components of the O&M cost estimates from 2013 to 2018 on the basis of cost escalation indices particular to each cost category. The same real escalation rates used to escalate the overnight capital costs in the previous section (see Table 12) have

been also used to escalate the O&M costs. In this case, we escalated the cost to 2018 using the escalation rate for each component.

D. Implications for Economic Life

The O&M estimates include the costs for routine maintenance and for funding a long-term service agreement (LTSA) to cover major maintenance. The major maintenance costs are sufficient to repair and replace major parts (*e.g.*, turbine blades, fuel nozzles, combustion liners, *etc.*) at the intervals recommended by the turbine vendor. Normally, this would be a sufficient level of funding to cover at least three major maintenance cycles (approximately 144,000 to 150,000 equivalent hours or 7,200 equivalent starts). This would be expected to result in an economic life of at least 30 years for a simple-cycle turbine, and 25–30 years for combined-cycle turbine operating at a capacity factor of 50–60%. The O&M costs do not include major expenditures, such as for rotor replacement, or extending the normal plant life. However, other considerations caused us to limit the economic life in our financial model to only 20 years, as discussed in Section VII.B

E. Summary of O&M Costs

A summary of the O&M costs for each candidate reference technology is shown in Table 14.

Table 14
Summary of O&M Costs for Candidate Reference Technologies

O&M Costs	Units	LM6000	LMS100	F-Class Frame	Combined
		Combustion Turbine <i>173 MW</i>	Combustion Turbine <i>188 MW</i>	Combustion Turbine <i>417 MW</i>	Cycle Gas Turbine <i>715 MW</i>
Fixed O&M					
Labor	2013\$	968,000	968,000	1,058,000	3,225,000
Materials and Contract Services	2013\$	330,000	308,000	575,000	4,018,000
Administrative and General	2013\$	374,000	368,000	534,000	870,000
Site Leasing Costs	2013\$	247,000	190,000	190,000	380,000
Property Taxes	2013\$	2,218,000	2,096,000	2,448,000	5,488,000
Insurance	2013\$	1,773,000	1,675,000	1,957,000	4,388,000
Total Fixed O&M	2013\$	5,910,000	5,605,000	6,762,000	18,369,000
Total Fixed O&M	2013\$/kW-yr	34.16	29.84	16.23	25.69
Total Fixed O&M	2018\$/kW-yr	39.16	34.24	18.61	29.31
Variable O&M					
Major Maintenance	2013\$/MWh	3.43	2.86	2.01	1.32
Other VOM	2013\$/MWh	2.52	2.52	1.65	1.03
Total Variable O&M	2013\$/MWh	5.95	5.38	3.66	2.35
Total Variable O&M	2018\$/MWh	6.78	6.13	4.17	2.68

Source: S&L analysis.

VII. CONE CALCULATIONS

The Cost of New Entry (CONE) is the total contribution to capital and fixed cost recovery that a new resource would need to earn (from capacity, energy, and ancillary services revenues minus variable operating costs) in its first operating year to be willing to enter the market. CONE depends on the upfront capital and annual fixed O&M costs to which an entry decision commits the resource owner, as described in Sections V and VI. CONE also depends on the project's riskiness and associated cost of capital with which to discount future net revenues. Finally, CONE depends on the entrant's long-term view about future market conditions and its own performance, which affect its ability to recover capital and fixed costs over time, and thus determine how much it needs to recover in year one to achieve a Net Present Value (NPV) of zero.

Actual entrants may differ in the amounts they would accept in year one to be willing to enter. Some may have special cost advantages or disadvantages or already-sunk costs. They may have a particular optimistic or pessimistic long-term market view. However, for our estimate of CONE (and Net CONE), we assume the entrant has a generic cost structure and a fairly well-behaved, long-term equilibrium view of the capital recovery trajectory it can expect, as described in the following section.

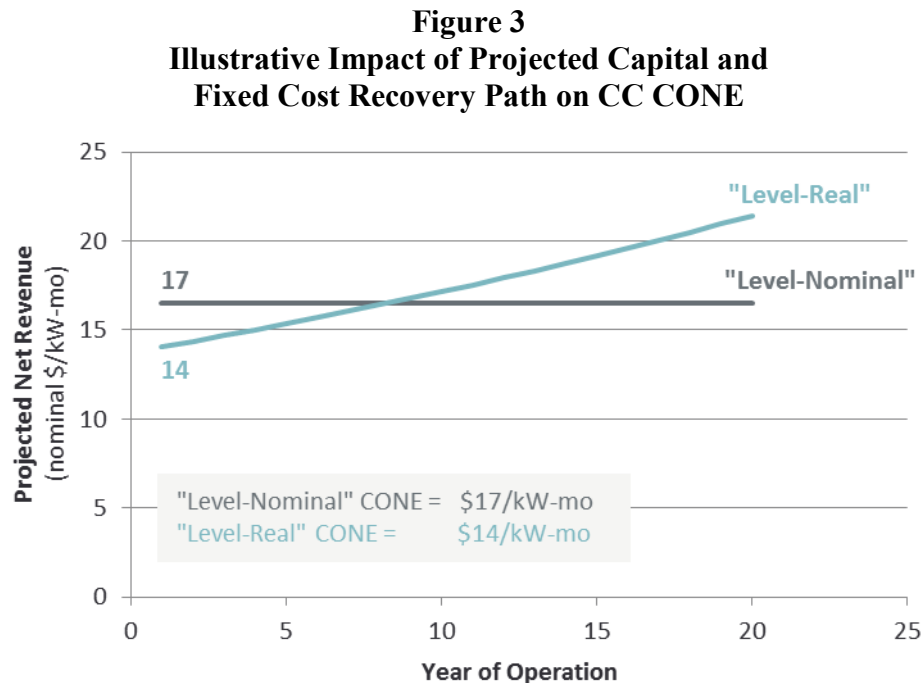
Our CONE calculation depends on a long-term market view, but it does not depend on potential short-term excursions of market prices caused by supply/demand shifts that make market prices deviate temporarily from long-term equilibrium conditions. We recognize that under volatile conditions new resources might aim to enter during a period of high market prices and temporarily earn more than needed on average, particularly if its own entry is likely to depress market prices in the following year. However, increasing the CONE parameter accordingly would cause the demand curve to over-procure on average. The demand curve we designed was calibrated to procure the desired amount of capacity if it is based on average annual net revenues (averaging out short-term volatility) the entrant would need at the beginning of its economic life.

On a related topic, one might argue that ISO-NE's multi-year capacity price lock-in option can only improve an entrant's medium-term expectations for capital and fixed cost recovery, and thus might lower CONE. However, we do not recommend adjusting CONE based on the lock-in option, for three reasons: (1) we understand that ISO-NE supports the lock-in as an entry inducement to counteract perceived barriers to investment in New England, and downward-adjusting CONE would undo some of its purpose; (2) downward adjustments of Net CONE could contribute to the price discrimination impact the lock-in has on existing generation; and, in any case, (3) the positive effect of the lock-in on medium term returns may be offset by lower prices in the long-term if future entrants would reduce their bids due to the lock-in available to them.

A. Long-Term Market View

As noted above, CONE depends on a new entrant's long term view of its ability to recover capital and fixed costs beyond the first operating year. Those prospects depend on expectations of future net revenues from selling capacity, energy, and ancillary services minus variable operating costs. Expectations of rising net revenues, reflecting anticipated increases in market prices, would tend to reduce CONE. In contrast, a trend of declining (or

flat) net revenues would increase CONE. The impact of different expected net revenue trajectories on CONE is illustrated for the CC in Figure 3.³⁴



In this example, if net revenues contributing to capital and fixed cost recovery are expected to stay constant in nominal terms (declining in real terms) over the long-term, the estimated “level-nominal” CONE is \$17/kW-month for the first delivery year. However, if net revenues are projected to remain constant in real terms over time (increasing in nominal terms with the rate of inflation), lower first-year revenues are acceptable since more of the plant’s investment cost recovery will occur in later years, as seen in the lower “level-real” CONE value of \$14/kW-month. More optimistic projections would further reduce CONE, whereas less optimistic projections would have the opposite effect. In all cases, the present value of all future net revenues is equal to the present value of capital and fixed O&M costs for the reference CC plant.

We determined that the “level-real” trajectory is reasonable for calculating CONE in this analysis. First, we assume load growth and retirements are sufficient for merchant generation entry to be necessary to maintain resource adequacy into the future. Thus future new entrants will set all-in market prices on average in the long term. They will set prices based on their own costs and performance. Second, we considered cost and performance trends based on historical data we analyzed for PJM in our 2011 report on RPM.³⁵ That analysis showed that for gas-fired technologies, capital costs have historically increased slightly faster than inflation (by about 0.6% per year), while performance and efficiency have consistently improved. Rising entry costs would tend to raise all-in market prices, since

³⁴ The two projected net revenues are of equal net present value equal to the present value of capital and fixed O&M costs for the reference CC plant in the Net CONE study.

³⁵ Johannes P. Pfeifenberger, Samuel A. Newell, Kathleen Spees, Attila Hajos, and Kamen Madjarov, *Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15*, August 26, 2011. See Section IV.A.3.

costlier new entrants would have to earn enough from capacity, energy, and ancillary services to be economically viable. However, performance improvements allow future entrants to earn more than older resources. The analysis showed that the performance effect has been enough to almost exactly offset the cost increase in excess of inflation, such that a given resource would tend to earn approximately constant real net revenues over time. If such trends continued, an entrant today could expect its net revenues to remain constant in real terms, growing in nominal terms at the rate of inflation.

B. Economic Life

The economic life of a power plant is an assumed value that reflects the time period over which developers expect to receive their return of and on capital. For the demand curve Net CONE analysis, we reviewed whether the 20-year economic life required by the tariff for the 2013 ORTP Study is reasonable to ensure that we are reflecting the view of developers properly.

In our review of economic life, we found reasons for assuming both a longer and shorter period. A longer economic life would be more in-line with the 30-plus year physical life that developers view assets. In addition, our fixed O&M costs are consistent with operating the plant over a 25 to 30-year timeframe and assume that no major equipment replacements would be required until the overhaul of the turbine rotor around year 25.

However, developers face threats to expected cash flows that may not be accounted for in our analysis, including: market risks, such as new technologies entering the market that could reduce expected net revenues below what we have accounted for in the “level-real” assumption; potential reductions in system load, given the region’s commitment to energy efficiency; and the risk of market intervention by states or other entities. These factors could depress expected future cash flows, with an effect similar to reducing the economic life of the asset.

We will maintain the economic life at 20 years for all technologies, which balances considerations of the physical life of generation resources with considerations of the additional factors that could depress expected cash flows. As a sensitivity analysis, we calculated that a shorter economic life of 15 years would increase CC CONE by \$2.2/kW-month, while the longer economic life of 30 years would decrease CONE by \$2.0/kW-month.

C. Cost of Capital

An appropriate discount rate is needed for translating uncertain future cash flows into present values and deriving the CONE value that makes the project NPV zero. It is standard practice to discount future all-equity cash flows (*i.e.*, without deducted interest payments) using an after-tax weighted-average cost of capital (ATWACC).³⁶ The appropriate ATWACC reflects the systemic financial market risks of the project’s future cash flows as a

³⁶ The “after-tax weighted-average cost of capital” (ATWACC) is so-named because it accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, with the weights corresponding to the debt-equity ratio in the capital structure. Cash flows to which the ATWACC is applied must include revenues, costs, and taxes on income net of depreciation (but not accounting for interest payments or their deductibility, since that is incorporated into the ATWACC itself).

merchant generating plant participating in New England’s capacity and energy markets. As a merchant project, the risks would be larger than for the average portfolio of independent power producers that have long-term contracts and other hedges in place. Furthermore, many investors have told us they perceive the New England market as being riskier than other markets, due to several factors that may affect either the expected cash flows or the systemic, market-correlated risk of the project and thus the cost of capital: a history of little merchant entry and substantial state-sponsored entry; a history of administrative pricing; a small market size with prices more sensitive to new entry and other shifts in supply and demand; and a low growth rate that can make the market take many years to recover from a recession or other causes of excess supply. ISO-NE’s multi-year price lock-in option for new entrants would offset some of that risk.

To estimate the cost of capital for such a project, we reviewed a broad range of reference points. As there is significant uncertainty in any single cost of capital estimate, we reviewed all of the available reference points and selected a level that is reasonable considering the wide range of values. The reference points that we are using include updated estimates for publicly-traded merchant generation companies (NRG, Calpine, and Dynegy) additional sources from previous analysis by Brattle, fairness opinions for merchant generation divestitures, and analyst estimates. Supplementing our analysis with estimates from other financial analysts is valuable as others’ methodologies may account for market risks and estimation uncertainties differently from ours. We derived each of the reference points as follows, with results summarized in Table 15.

- **Publicly Traded Companies:** similar to the 2013 ORTP Study, we derived ATWACC estimates using the following standard techniques.
 - *Return on Equity:* We estimate the return on equity (ROE) using the Capital Asset Pricing Model (CAPM). The ROE for each company is derived as the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company’s “beta.”³⁷ We calculated a risk-free rate of 3.7% using a 15-day average of 30-year U.S. treasuries as of November 2013.³⁸ We estimated the expected risk premium of the market to be 6.5% based on the average of values provided by Credit Suisse and Ibbotson.³⁹ The “beta” describes each company stock’s (five-year) historical correlation with the overall market, where the “market” is taken to be the S&P 500 index. The resulting return on equity ranges from 7.1–11.9% for the companies included in the analysis, as shown in Table 15.⁴⁰

³⁷ Richard Brealey, Stuart C. Myers, and Franklin Allen. *Principles of Corporate Finance*. New York: McGraw-Hill/Irwin, 2011.

³⁸ Bloomberg, Bloomberg Professional Service. Data downloaded November 14, 2013. (Bloomberg, 2013). Risk free rate calculated based on 30 year U.S. bond yields.

³⁹ The Ibbotson market risk premium is 6.7% and the Credit Suisse market risk premium is 6.2%. Ibbotson, *S&P 500 Valuation Yearbook*, Chicago: Morningstar, 2013. Elroy Dimson, Paul Marsh, and Mike Stauton. *Credit Suisse Global Investment Returns Sourcebook 2013*, Zurich: Credit Suisse Research Institute, February 2013.

⁴⁰ Dynegy financial characteristics are currently significantly different from Calpine and NRG as it is in the final stages of emerging from bankruptcy. However, we believe that it still can provide a useful reference point for estimating the cost of capital for a merchant generator.

- *Cost of Debt*: We estimate the cost of debt (COD) by compiling the unsecured senior credit ratings for each merchant generation company and examining the bond yields associated with those credit ratings. In Standard and Poor’s (S&P) credit ratings, a company receives a higher rating based on its ability to meet financial commitments, with “AAA” being the highest rating and “D” being the lowest. Calpine and Dynegy’s credit ratings are “B,” with an associated cost of debt of 8.7%, while NRG’s is “BB” with a 7.5% cost of debt.⁴¹
- *Debt/Equity Ratio*: We estimate the five year average market-value debt-equity ratio for each merchant generation company, using company 10-Ks for debt value and Bloomberg for market value of equity.
- **April 2011 Brattle Estimates** were calculated using a similar approach and have been adjusted downward by 0.9% for the current analysis based on the difference in the risk-free rate between April 2011 (4.3%) and November 2013 (3.4%).
- **The other reference points** come from publicly available values used by financial advisors and analysts in valuations associated with mergers and divestitures. For example, the financial advisors for the acquisition of GenOn by NRG used discount rates of 7.0–8.5% for NRG and 8.5–9.5% for GenOn in their discounted cash flow analyses associated with the merger. While there are no details provided on how these ranges were developed, we find these values provide useful reference points for estimating the cost of capital. The values in Table 15 have been adjusted upward by 0.7% due to the change in risk-free rates since the original estimates were developed by the financial analysts in 2012.

⁴¹ Bloomberg, 2013.

Table 15
Summary of Cost of Capital Reference Points and Recommended ATWACC

Company	Brattle Updated ATWACC Estimates						Prior Estimates Adjusted to Nov 2013 Risk-Free Rate			
	S&P Credit Rating	Equity Beta	Return on Equity	Cost of Debt	Debt/ Equity Ratio	After Tax WACC	July 2012			
							Financial Advisor Estimates for NRG- GenOn Merger	Apr 2011 Brattle Estimates	2011 Analyst Estimates	2011 Fairness Opinions
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	
Publicly Traded Companies										
Calpine	B	1.29	11.9%	8.7%	61/39	7.8%		6.7%	6.6%	
NRG	BB	1.04	10.4%	7.5%	73/27	6.1%	7.7 - 9.2%	6.3%	6.2%	
Dynegy	B	0.49	7.1%	8.7%	42/58	6.1%		7.4%	7.1 - 11.1%	
Acquired Companies (previously traded)										
GenOn Energy							9.2 - 10.2%	10.3%	7.6 - 9.6%	
Mirant								8.0%	7.6 - 8.6%	
Merchant Generation Divestitures										
FirstEnergy Merchant Generation										7.1 - 8.1%
Allgheny Merchant Generation										7.1 - 7.6%
Duke's Merchant Generation										7.3 - 8.3%
Recommendation			13.8%	7.0%	60/40			8.0%		

Sources and notes:

[1]: Bloomberg, 2013.

[2]: Brattle analysis.

[3] = Assumed risk-free rate (3.70%) + assumed market risk premium (6.50%) × [2].

[4]: Bloomberg, 2013.

[5]: Market structure calculated by Brattle using company 10-Ks for debt value and Bloomberg for market value of equity.

[6] = (% Debt) × [4] × (1 - [6]) + (% Equity) × [3]

[7] - [10]: 2011 and 2012 estimates have been adjusted based on changes in the risk-free rate.

The risk-free rates were 4.3% in April 2011, 2.7% in July 2012, and 3.4% November 2013.

(Bloomberg, 2013)

[7]: NRG Energy Inc. and GenOn Energy, *Joint Proxy Statement/Prospectus for Special Meeting of Stockholders to be Held on Friday, November 9, 2012*, October 5, 2012, pp. 63, 70, and 75.

[8] - [10]: 2011 PJM CONE Study contains original analysis for [9] and citations to original sources for [10] and [11].

Based on this set of reference points and our assumption of merchant entry in New England's market, we believe an 8.0% ATWACC is the most reasonable estimate for the purpose of estimating CONE for the ISO-NE demand curve. That value is above the cost of capital of Calpine and NRG, both of which have some long-term contracts and hedges in place, and it is near the mid-point of the range of the additional reference points. One might argue that ISO-NE's multi-year lock-in price option reduces risk much like a short-term capacity-only PPA, but the remaining life of the plant faces merchant risks that may be perceived to be higher than in other RTO markets, as noted above.

The 8.0% ATWACC is an important input into the CONE calculation. For example, a 50 basis points higher (or lower) ATWACC would increase (or decrease) the CONE of a CC by about \$0.6/kW-month. Although the specific assumptions on capital structure, ROE, and COD corresponding to our ATWACC have almost no impact on the CONE calculation, we do need to assume specific values in order to quantify interest during construction and depreciable capital costs. Based on stakeholder input, we assumed a capital structure of 60/40 debt-equity ratio to reflect typical projects' capital structures and their associated ROE and COD. For an ATWACC of 8.0% with a 60/40 capital structure, we assumed a COD of

7.0% and ROE of 13.8%, as shown in Table 15. Some of the stakeholders commented that these values are reflective of the value that they are currently seeing used in the market.

Stakeholders requested a comparison of the ISO-NE Net CONE cost of capital to the NYISO Demand Curve Reset (DCR) cost of capital, which is shown in Table 16. The comparison shows that the final ATWACC value for ISO-NE is just slightly lower than the NYISO DCR with the most significant differences coming from the more leveraged capital structure and higher associated tax-benefits of debt in our estimates for ISO-NE.

Table 16
ISO-NE Net CONE and NYISO DCR
Cost of Capital Comparison

Recommended Inputs	ISO-NE Net CONE	NYISO DCR
Return on Equity	13.8%	12.5%
Cost of Debt	7.0%	7.0%
Debt/Equity Ratio	60/40	50/50
WACC	9.7%	9.8%
ATWACC	8.0%	8.3%

Source: Brattle analysis and NERA Economic Consulting, *Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator: Final Report*, August 2, 2013.

D. Other Financial Assumptions

Calculating CONE requires several other financial assumptions about general inflation rates, tax rates, depreciation, and interest during construction.

Inflation enters many aspects of the Net CONE analysis, including estimates of future capital costs and the escalation rate of total net revenues, although it does not have a major impact on the results.⁴² We estimated future twenty-year inflation rates based on bond market data, Federal Reserve estimates, and consensus U.S. economic projections. The implied inflation rate over twenty years from treasury yields is 2.2% and the Cleveland Federal Reserve estimate of inflation expectations is 1.9% over twenty years.⁴³ The most

⁴² A 0.25% change in the inflation rate affects CC Net CONE by only +/- \$0.1/kW-month.

⁴³ As stated on the Cleveland Federal Reserve website, “The Cleveland Fed’s estimate of inflation expectations is based on a model that combines information from a number of sources to address the shortcomings of other, commonly used measures, such as the “break-even” rate derived from Treasury inflation protected securities (TIPS) or survey-based estimates. The Cleveland Fed model can produce estimates for many time horizons, and it isolates not only inflation expectations, but several other interesting variables, such as the real interest rate and the inflation risk premium.” Federal Reserve Bank of Cleveland, *Cleveland Fed Estimates of Inflation Expectations*, Accessed July 16, 2013. Available at http://www.clevelandfed.org/research/data/inflation_expectations/.

forward looking forecast in the Blue Chip Economic Indicators report is 2.3%.⁴⁴ Based on these sources, we assumed for the Net CONE calculations an average long-term inflation rate of 2.25%.

We calculated income tax rates based on current federal and state tax rates. The marginal federal income tax rate for 2013 is 35%.⁴⁵ As our reference technologies are assumed to be located in Worcester County, Massachusetts, the state income tax rate is 8.0%.⁴⁶ The effective income tax rate is thus calculated to be 40.2%.⁴⁷

We calculated depreciation based on the current federal tax code, which allows generating companies to use the Modified Accelerated Cost Recovery System (MACRS) of 20 years for a CC plant and 15 years for a CT plant.⁴⁸

To calculate the annual value of depreciation, the “depreciable costs” (different from the overnight and installed costs referred to earlier in the report) for a new resource are the sum of the depreciable overnight capital costs and the accumulated interest during construction (IDC). Several capital cost line items have been determined to be non-depreciable, including fuel inventories and working capital, and have not been included in the depreciable costs. IDC is calculated based on the assumption that the construction capital structure is the same as the overall project, *i.e.*, 60% debt and 7.0% COD.

E. Summary of CONE Values

A summary of the assumptions discussed above for calculating CONE is shown in Table 17.

⁴⁴ Blue Chip Economic Indicators, *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers, March 2013. We used the consensus ten-year average consumer price index (CPI) for all urban consumers.

⁴⁵ Internal Revenue Service, *2012 Instructions for Form 1120, U.S. Corporation Income Tax Return*. January 25, 2013. Available at <http://www.irs.gov/pub/irs-pdf/i1120.pdf>.

⁴⁶ Massachusetts Department of Revenue, *2012 Massachusetts Corporation Excise Return Form 355*. Available at <http://www.mass.gov/dor/docs/dor/forms/corp12/355/355-instr.pdf>.

⁴⁷ The effective combined income tax considers the federal deduction that is allowed for state income taxes paid.

⁴⁸ Internal Revenue Service, *Publication 946, How to Depreciate Property*, February 15, 2013. Available at <http://www.irs.gov/pub/irs-pdf/p946.pdf>.

Table 17
CONE Assumptions

Component	Value
Long-Term Revenue Projections	Constant in Real Terms
Economic Life	20 years
ATWACC	8.0%
Inflation	2.25%
Depreciation	15 or 20 Yr MACRS
Federal Taxes	35%
MA State Taxes	8%
Interest During Construction	60% debt, 7% COD

Sources and notes: Brattle analysis. Depreciation for a CC is 20yr MACRS and for a CT is 15yr MACRS.

Based on these assumptions and the cost estimates for each candidate reference technology, we calculate a levelized capital cost, in terms of dollars per kilowatt-month.⁴⁹ A summary of CONE values for the candidate reference technologies is shown in Table 18.

Table 18
Candidate Reference Technology CONE Summary

Reference Technology	Installed Capacity MW	Total Plant Capital Cost \$m	Overnight Cost \$/kW	Depreciation Schedule	After-Tax WACC %	Capital Costs \$/kW-mo	Fixed O&M \$/kW-mo	Gross CONE \$/kW-mo
<i>Rest of Pool</i>								
4x0 LM6000	173	\$352	\$1,965	15yr MACRS	8.0%	\$17.91	\$3.26	\$21.18
2x0 LMS100	188	\$333	\$1,711	15yr MACRS	8.0%	\$15.60	\$2.85	\$18.45
2x0 Frame CT	417	\$389	\$902	15yr MACRS	8.0%	\$8.21	\$1.55	\$9.76
2x1 CC	715	\$900	\$1,178	20yr MACRS	8.0%	\$11.59	\$2.44	\$14.04

Source: Brattle and S&L analysis.

VIII. REVENUE OFFSETS

A. Approach

We calculate the first year E&AS margins for each candidate reference technology using historical margins for similar plants adjusted for differences in electricity prices indicated by available futures settlement prices. Our approach for calculating E&AS margins

⁴⁹ The calculation of levelized capital costs results in an annual capital charge rate of 11.1% for the CC and 10.6% for the CTs. The annual capital charge rate is the levelized capital costs (including depreciation) divided by the installed costs. Available at: http://www.iso-ne.com/committees/comm_wkgrps/mrktts_comm/mrktts/mtrls/2014/mar192014/a02_iso_net_cone_capital_budgeting_model_03_14_14.xlsx.

is similar to the 2013 ORTP Study with several enhancements based on stakeholder comments.

We first identify existing units that are similar to our candidate CC and CT technologies for calculating historical E&AS margins. Our criteria for identifying “representative” units have changed from the 2013 ORTP Study and are explained for each technology in the sections below.

Next, we estimate the E&AS margins the representative units earned from October 2011 through September 2013, which is the most recent three-year period for which all input data needed for our calculation was available. We obtained settlement data from ISO-NE that includes day-ahead and real-time energy revenues, net commitment period compensation (NCPC) credits, regulation revenues, real-time reserves (RTR) revenues, forward reserve market (FRM) revenues, blackstart payments, and VAR capacity cost payments.⁵⁰ We estimated each unit’s costs based on fuel usage, spot gas prices at Algonquin Citygates, GHG allowance costs from RGGI, and variable O&M costs estimated by S&L (see Section VI).⁵¹ Fuel costs are adjusted for differences in heat rates between historical CCs and new entrant CCs and between different CT technologies, as described below. Finally, we calculate each unit’s adjusted E&AS margins by subtracting adjusted costs from revenues and calculate a capacity-weighted average E&AS margin (\$/kW-month) for each technology.

We then adjust historical margins for differences between historical on-peak prices and on-peak futures settlement prices, for two reasons: (1) to normalize the idiosyncratic market conditions that may have occurred in historical years, thus adding stability to the Net CONE calculation and improving the demand curve’s performance; and (2) to reflect future market conditions. There is no perfect way to project future prices, nor to estimate E&AS margins under such conditions, but we use an approach similar to the one we used for ORTP. We project electricity prices at Mass Hub using futures settle prices from ICE.⁵² We then estimate first-year E&AS margins assuming that the margins vary linearly with electricity prices.

Finally, we consider the expected impact on revenue offsets of the proposed Pay for Performance (PFP) market rules and the Peak Energy Rent (PER) deduction on Net CONE. PFP would provide a small net benefit to new resources, which reduces Net CONE. PER is larger and has the opposite effect on Net CONE since it reduces resources’ net revenues. Both of these values are calculated based on an assumed number of scarcity hours (H) consistent with analysis ISO-NE conducted and our consideration of forward market heat rates.

⁵⁰ Revenue data through January 2014 were provided by ISO-NE Market Analysis and Settlements department on February 21, 2014 with the most recent three months preliminary. Due to time lags in the fuel cost data, we calculated revenues through September 2013 when all results are considered final.

⁵¹ Fuel usage and prices are from Ventyx, 2013 and RGGI allowance costs are from the Regional Greenhouse Gas Initiative website (http://www.rggi.org/market/co2_auctions/results).

⁵² Mass Hub was chosen due to its location in a non-constrained zone and the volume of trading of Mass Hub electricity futures.

B. Historical E&AS Margins

1. Combined Cycle Historical E&AS Margins

The first step in calculating historical CC E&AS margins is to select the representative operating CC units in New England. We reviewed revenue data from ISO-NE for 20 CC plants and removed the plants that are not representative of the specified reference CC unit based on heat rate, fuel supply arrangements, and mode of operation.

- **Heat Rate Screen:** As S&L calculated that the CC reference technology will have a summer/winter average heat rate of 7,138 Btu/kWh, we removed six plants in the ISO-NE dataset with annual operating heat rates in excess of 8,000 Btu/kWh.⁵³ Such plants are not representative of the reference CC as they would operate less often and at higher costs.
- **Fuel Supply Screen:** As we assume the reference CC plant is located in Worcester County, MA with gas purchases based on daily spot prices at Algonquin Citygates, we removed three plants that are known to have firm fuel capacity and three plants that purchase gas indexed to the Iroquois Zone 2 gas price.
- **Mode of Operation Screen:** We removed two plants due to different modes of operation from the reference CC, which include providing district heating and being operated at a capacity factor (<20%) that is more often attributed to a peaking unit.

Six plants remained, two of which are located in Massachusetts, two in Rhode Island, one in New Hampshire, and one in Maine, with an average capacity factor of 58% and a realized capacity-weighted average heat rate of 7,400 Btu/kWh across all output levels. While a specific location in Worcester County MA was chosen for developing detailed capital and fixed O&M cost estimates representative of the ROP capacity zone, developing the E&AS margins required including plants from a larger geographic region that meet our screening criteria so as not to reduce the sample set to just a few plants. All the plants included have typical operations and show little geographical variation in net revenues and are thus reasonable data points for calculating the ROP value.

We estimated historical E&AS margins for the representative units following the methodology outlined in the previous section, including an adjustment to fuel costs to better represent the heat rate of the reference unit.⁵⁴ Our heat rate adjustment is based on the following: over the past three years, the six representative units have operated with a realized capacity-weighted average heat rate of 7,400 Btu/kWh.⁵⁵ Because realized average heat rates reflect a range of output levels with less efficiency than at full load, the average is not directly comparable to the full-load average heat rate specified for the reference unit. However, it is reasonable to assume that the new reference unit will perform better than the

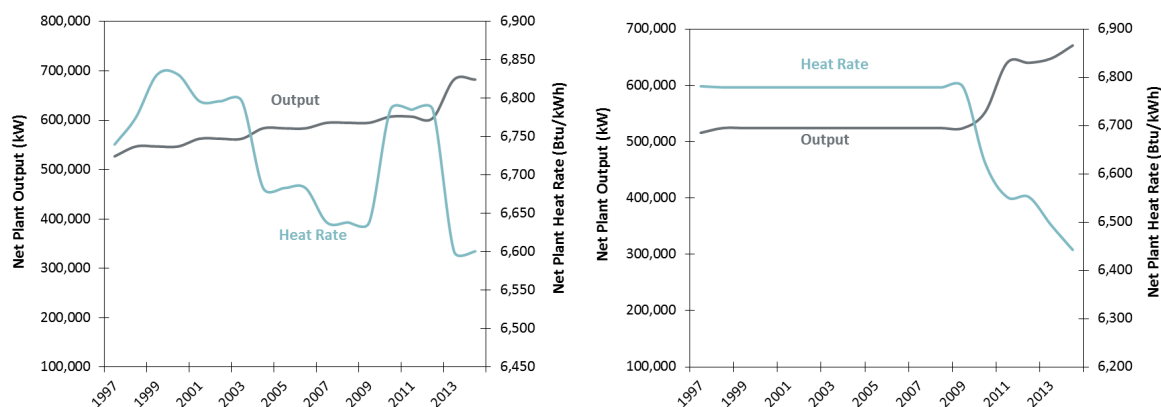
⁵³ Comparable to operating units, the reference unit's summer/winter average heat rate of 7,138 Btu/kWh is the average heat rate between overhauls and not the new-and-clean heat rate.

⁵⁴ We calculated CC fuel costs in this analysis using daily gas prices and fuel usage to accommodate the daily-shifting gas prices during the winter of 2013.

⁵⁵ Average heat rates were estimated by dividing total fuel consumption by net electrical output in each month of the historical three-year period.

representative units because the technology has advanced.⁵⁶ Our review of the performance of new Siemens and GE combustion turbines in a 2×1 combined cycle configuration since 1997, as shown in Figure 4, led us to assume that the current CC technology will have a heat rate that is 200 Btu/kWh lower than our representative units, which were built primarily in the late 1990s and early 2000s. Thus we adjusted the representative units' fuel costs to arrive at adjusted historical margins more representative of the reference unit.

Figure 4
Historical Development of CTs in 2×1 Combined Cycle Configuration
(a) Westinghouse-Siemens F-Class **(b) GE-7FA Combustion Turbine**
Combustion Turbine

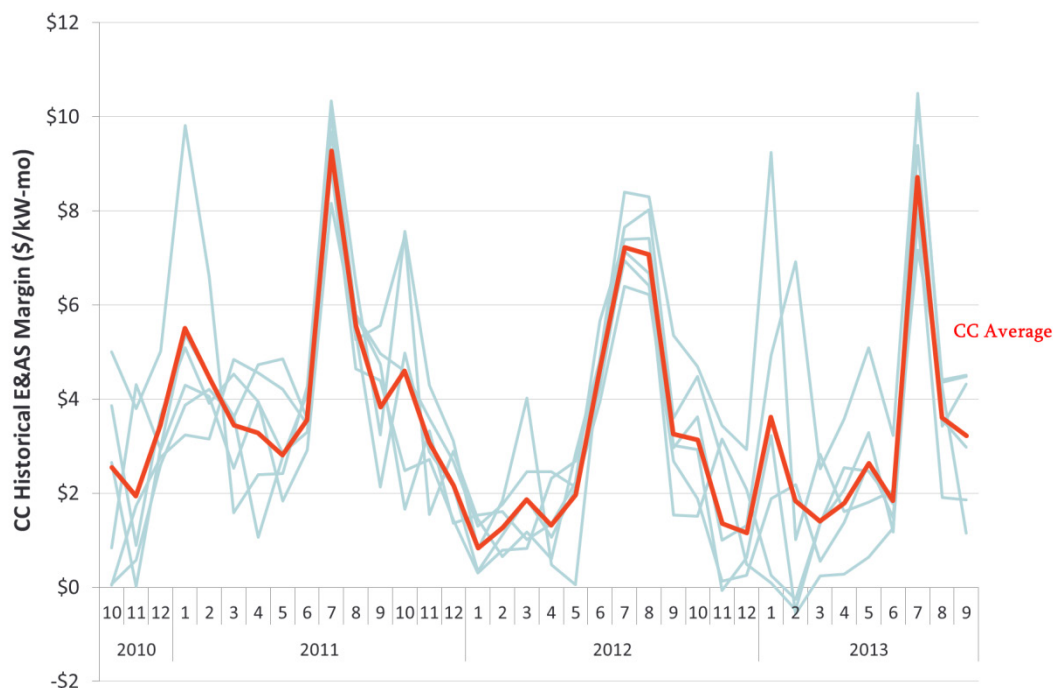


Source: Gas Turbine World Handbook with adjusted auxiliary power.

Using this approach, we calculated historic E&AS margins that are representative of the reference CC being evaluated in this analysis. The monthly CC historical E&AS margins over the time period analyzed are shown in Figure 5 with the annual averages shown in Table 19. In Section VIII.D below, these historically-based E&AS margin estimates will be adjusted to the 2018/2019 commitment period based on futures settlement prices.

⁵⁶ The reference unit will perform better than the representative units partly because it starts out new-and-clean—a temporary advantage that we exclude in favor of a more representative average heart rate between major overhauls.

Figure 5
CC Historical Monthly E&AS Margins for New England Based on Six Plants



Source: Brattle analysis of data from ISO-NE and Ventyx.

Table 19
Historical Annual Average CC E&AS Margins for New England

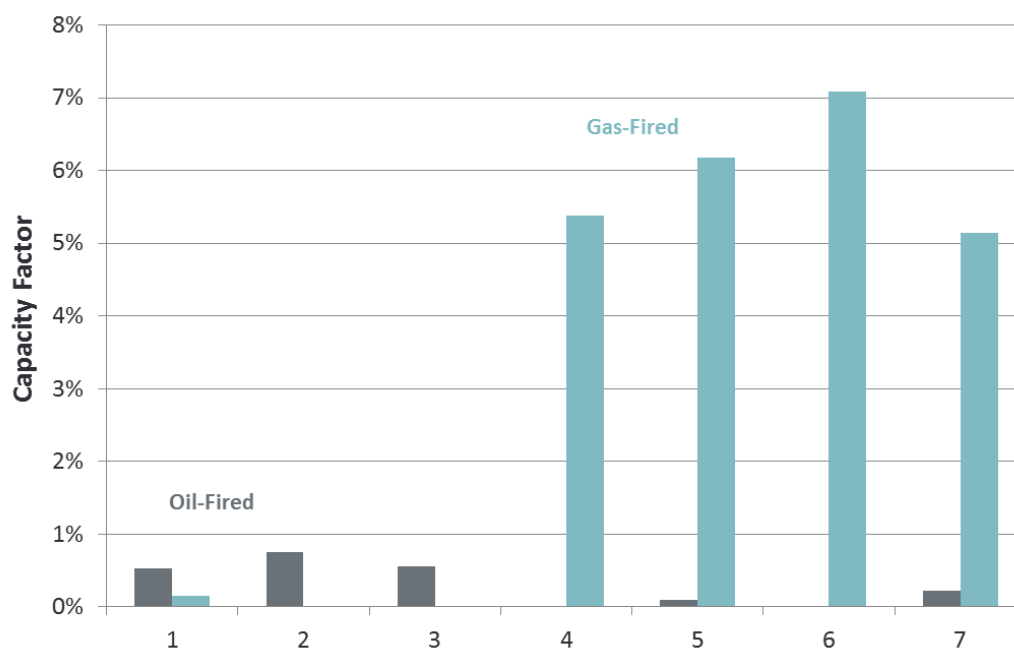
Year	CC \$/kW-mo
2010/2011	4.14
2011/2012	3.28
2012/2013	2.86

Sources and notes: Brattle analysis of data from ISO-NE and Ventyx, 2013. Annual values are calculated for October to September.

2. Combustion Turbines Historical E&AS Margins

Similar to the CC, we calculated historical E&AS margins for the CTs by reviewing revenue data from ISO-NE. Our review of the operations of CT plants found that the newest CTs have been earning a significant portion of their revenues from the forward reserve market (FRM). As such, they generate rarely and only in real-time, since providers of forward reserves are subject to restrictions on their participation in the energy market. In addition, when they do operate they tend to do so primarily with oil due to difficulties obtaining gas on short notice. The difference in operations of the most recently built plants can be seen in Figure 6, which shows the capacity factor for seven different CT plants in New England in order of their commercial online date (1 is the most recent). The newest CTs have been operating with capacity factors less than 1%, primarily on oil.

Figure 6
Combustion Turbine Capacity Factor for Oil and Gas Operations



Sources: Unit generation data obtained from Ventyx, 2013 based on Continued Emissions Monitoring Systems (CEMS) dataset as reported by the generators to EIA. Plants names not included to keep plant-specific revenue data confidential.

We assume that the reference CT plants in our analysis would be expected to also bid into the FRM and operate similarly to the newest CTs in New England. Based on this assumption, we selected the most recent plants for calculating historical E&AS margins for the reference CTs.⁵⁷

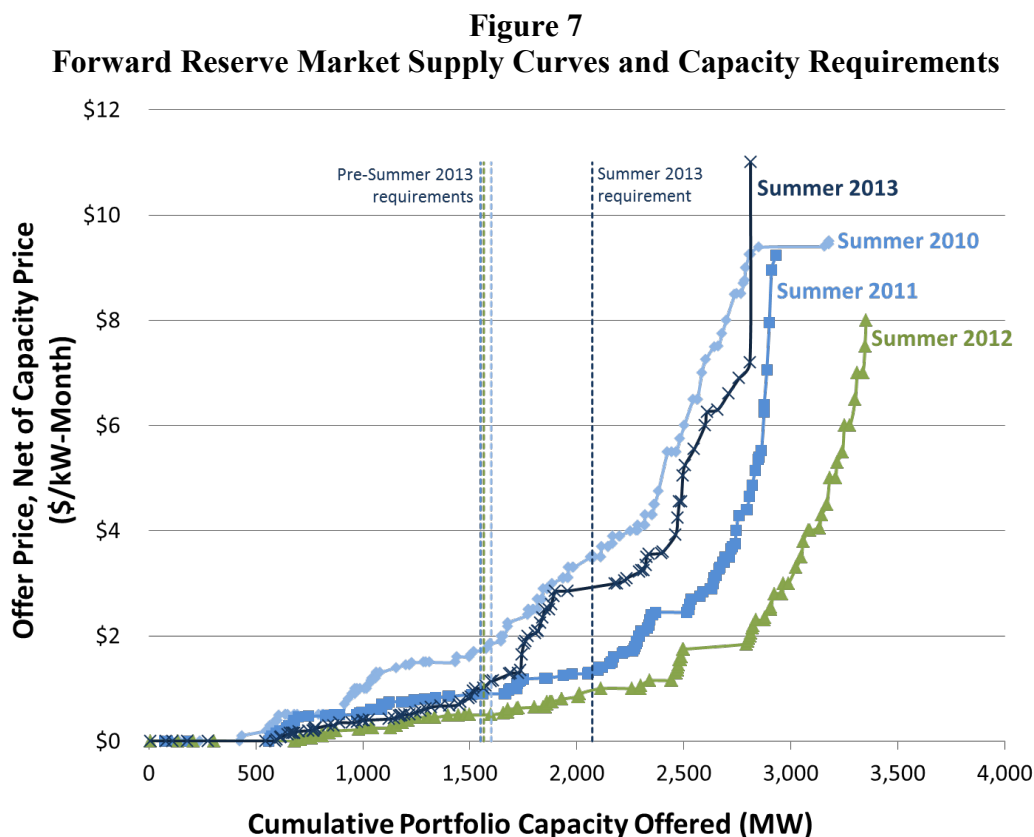
We calculated the historical E&AS margins using the market revenue data provided by ISO-NE and by calculating the fuel costs based on the estimated gas and oil usage on a monthly basis.⁵⁸ We corrected the market revenue data for real-time reserve paybacks that occur due to FRM obligations, as the market settlement data does not account for them.⁵⁹

⁵⁷ As FRM obligations are held, and thus revenues received, on a portfolio-wide basis, we included only units that are within a single portfolio in our calculation to ensure that all FRM revenues were included in the analysis.

⁵⁸ We estimated the split between gas and oil operation based on CO₂ emissions data provided by Ventyx, 2013.

⁵⁹ The market settlement data received from ISO-NE does not account for real-time reserve paybacks for units that hold FRM obligations, which are referred to by ISO-NE as forward reserve obligation charges. If a CT provides real-time reserves, they are initially paid for doing so, which is included in the market settlement data. A later process is then used to calculate the quantity that the holder of a CT portfolio must pay back to ISO-NE in the form of the forward reserve obligation charge so that they are not compensated twice for providing the same reserve product. The ISO-NE Markets and Settlement Department provided us with the monthly payback data for the representative units to more accurately represent the actual revenues received by CT plants that hold FRM obligations, as the reference CT is expected to do.

Stakeholders commented that the revenues for the reference CT should consider only the most recent FRM prices as there was a change in the market fundamentals over the three year period that we are using for calculating historical E&AS margins. To better understand the FRM market, we reviewed the supply curves, as shown in Figure 7. If the 2013 supply curve is representative of the future, additional entry of just a few hundred MW of fast-start capacity could significantly lower the FRM clearing prices.



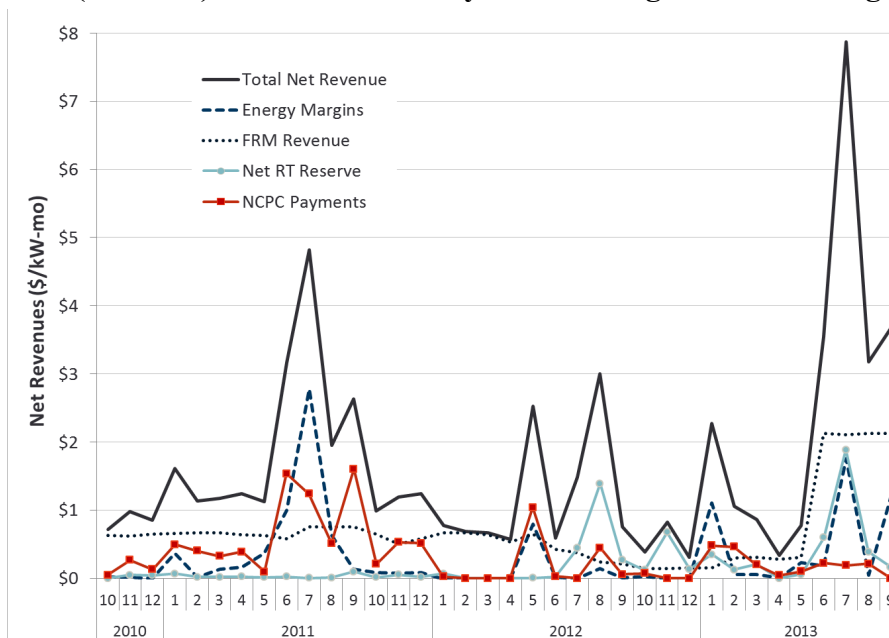
Source: Brattle constructed supply curves based on ISO-NE data available at Forward Reserve Auction Offer Data Report obtained from:
http://www.iso-ne.com/markets/hstdata/mkt_offer_bid/fr_auctn_offrs/index.html

For this reason and to remain consistent with our approach for the CC E&AS margins, we calculate the historical E&AS margins for the reference CTs using the most recent three years of data available, which includes FRM prices that range from \$0.35 to 3.00/kW-month over that time.

Because the representative units are all LM6000 turbines, the historical E&AS margins without any adjustments describe only that technology. The monthly CT historical E&AS margins for LM6000 turbines over the time period analyzed are shown in Figure 8. The monthly revenues are broken out into the different products (energy, net real-time reserves, FRM, and NCPC).⁶⁰ The higher FRM revenues can be clearly seen starting in the summer of 2013.

⁶⁰ Net real-time reserves are calculated by subtracting the FRM obligation charges from the real-time reserve revenues in the market settlement data provided by ISO-NE.

Figure 8
CT (LM6000) Historical Monthly E&AS Margins for New England



Source: Brattle analysis of ISO-NE data.

The uncertainty in future FRM prices significantly increases the overall uncertainty of future CT E&AS margins. This is especially true due to the larger portion of overall revenues that CTs receive from the FRM, as shown in Figure 8. While CT plants have lower uncertainty in their energy margins relative to CC plants due to their limited hours of operation, the recent fluctuations in FRM prices add uncertainty to our estimates of E&AS margins.

For calculating E&AS margins for the other reference CT technologies (Frame CT and LMS100), we assumed that similar FRM revenues can be achieved by all turbines as they are all able to ramp up to 100% output in 30 minutes. However, we have taken the differences in heat rate into account using the same approach as we used for the difference in CC heat rate by adjusting fuel costs proportionally to the heat rate.

The resulting annual average E&AS margins for all CT reference technologies are shown in Table 20. In Section VIII.D below, these historically-based E&AS margin estimates will be adjusted to the 2018/2019 commitment period based on futures settlement prices..

Table 20
CT Historical Annual Average E&AS Margins for New England

Year	LM6000 \$/kW-mo	LMS100 \$/kW-mo	Frame CT \$/kW-mo
2010/2011	2.33	2.36	2.30
2011/2012	1.07	1.07	1.06
2012/2013	1.81	1.83	1.80

Sources and notes: Brattle analysis of data from ISO-NE and Ventyx, 2013. Annual values are calculated for October to September.

C. E&AS Margin Adjustment using Futures Settlement Prices

After historical E&AS margins are determined for each technology, the 2018/2019 E&AS margins are estimated based on the ratio of future electricity prices to historical electricity prices using Mass Hub On-Peak as the reference hub, as shown in the following equation.⁶¹ We believe this is a good model for the New England market based on analysis we conducted of historical patterns.

2018/19 E&AS Margin

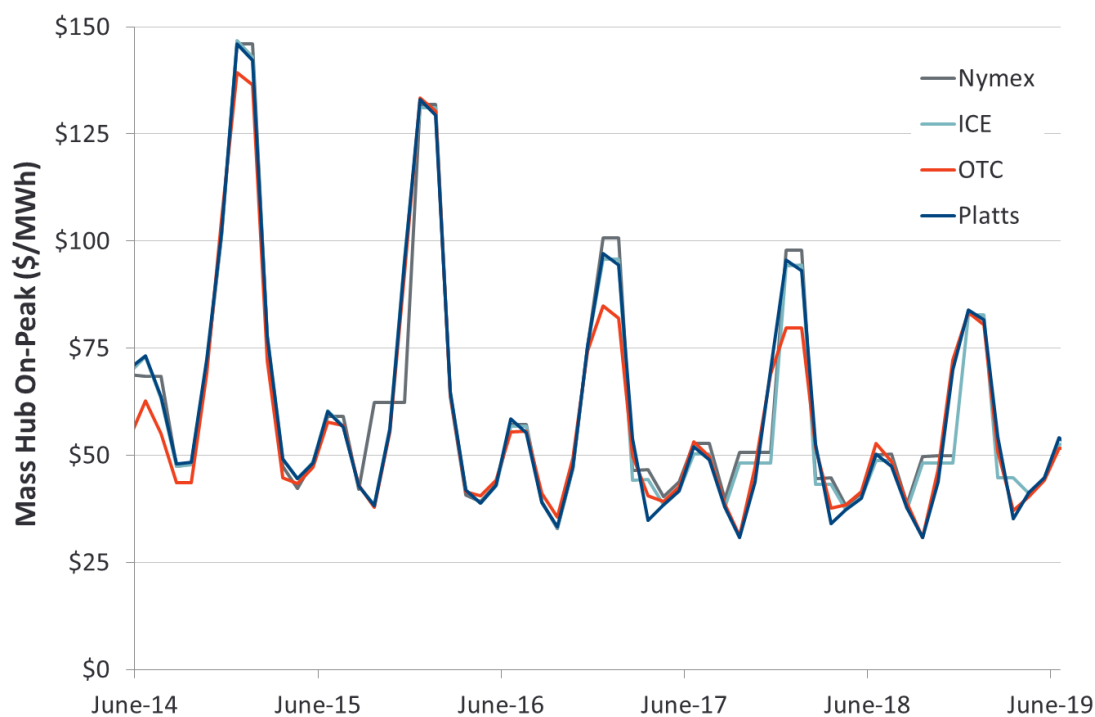
$$= \text{Historical E\&AS Margin} * \frac{\text{2018/2019 Mass Hub On-Peak Prices}}{\text{Historical Mass Hub On-Peak Prices}}$$

The 5×16 on-peak electricity futures settlement prices however will better reflect prices received by a CC than a CT that operates in a much narrower set of hours than 5×16. While we believe that this method will provide indicative margins for the CT, the method tends to increase the uncertainty of the CT E&AS margin relative to the CC margin.

We considered several approaches to projecting 2018/2019 electricity prices. Market simulation modeling could account for likely changes in fundamentals but would likely be too complicated, controversial, and opaque to stakeholders. We therefore chose to rely on futures settlement prices, which various trading platforms publish and that parties to futures contracts on those platforms use to mark their books and settle daily against contract prices. All sources we reviewed provided very similar values, as shown in Figure 9. (Platts is not actually a trading platform, but they publish a forward curve, which we purchased for comparison purposes.)

⁶¹ Mass Hub was chosen due to its location in a non-constrained zone and the volume of trading of Mass Hub electricity futures.

Figure 9
Mass Hub On-Peak Electricity Futures

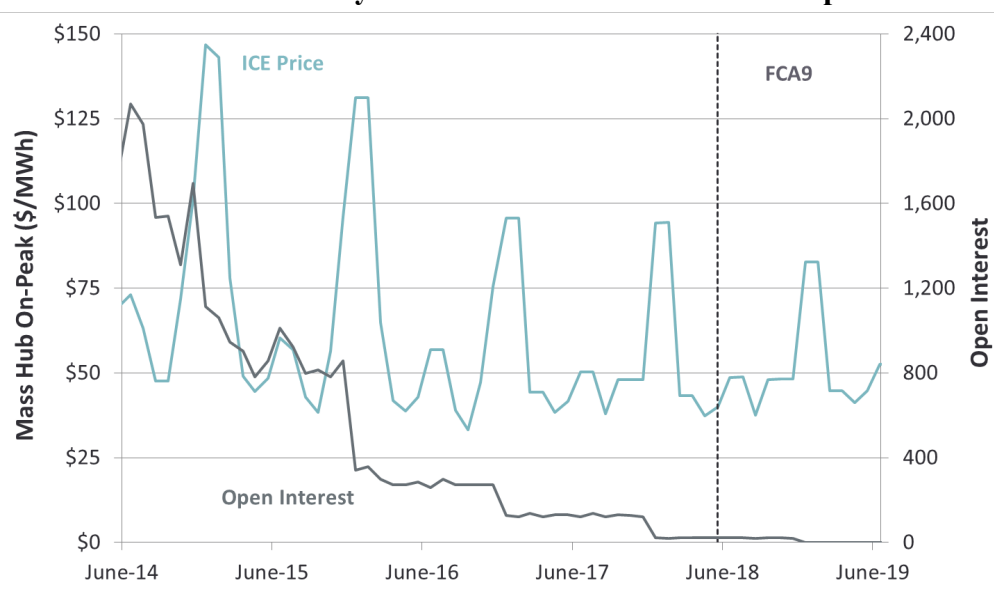


Sources: ICE futures were obtained from www.theice.com. NYMEX futures downloaded from Ventyx, 2013. OTC futures were compiled by OTC Global Holdings, downloaded from SNL, 2013. All futures settlement prices were published on Feb. 27, 2014. Platts forward curves were purchased from Platts on March 4, 2014.

We selected the ICE futures because we understand that ICE is the most active platform for trading electricity in the U.S. and because its settlement prices are publicly available.⁶² However, even ICE has very little trading volume and open interest on Mass Hub futures by 2018/2019, as shown in Figure 10. That means ICE's prices for that period are informed by few actual trades, and there are few existing futures contracts for delivery then that are settled daily based on those prices. However, the prices are close to those for 2016/2017 delivery, when open interest is greater. Overall, based on our judgment and stakeholder input, we determined that the ICE futures settlement prices are at least as good a source of prices for 2018/2019 as any other practical option.

⁶² ICE Mass Hub On-Peak electricity futures are available at <https://www.theice.com/marketdata/reports/ReportCenter.shtml> by selecting the following: Category: End of Day Report; Market: ICE Futures US. – Energy Div; Report: DMR – IFED Futures; Contract: NEP-ISO New England Massachusetts Hub Day-Ahead Peak Fixed Price Future. To reduce the impact of day-to-day volatility, we averaged settlement prices over the seven trading days of data available, which were February 20 – 28, 2014.

Figure 10
ICE Mass Hub Electricity Futures Settlement Prices and Open Interest



Source: ICE futures settlement prices and open interest were obtained from www.theice.com. See footnote 62 for more details.

Based on the historical E&AS margins and the electricity futures data, the projected E&AS margins for the candidate reference technologies in 2018/2019 are shown in Table 21. Note that these projections differ from projected E&AS margins in our 2013 ORTP Study. There, we projected higher electricity prices using a different approach that relied solely on the next 12 months of futures prices.⁶³ Here, if we estimated futures prices using the same approach, CC and CT E&AS margins would have been \$1.4/kW-month and \$0.8/kW-month higher, respectively.

Table 21
Projected 2018/2019 E&AS Margins

Reference Technology	Average Historical Margin \$/kW-mo	Projected 2018/2019 Margin \$/kW-mo
LM6000	\$1.74	\$1.67
LMS100	\$1.75	\$1.69
Frame CT	\$1.72	\$1.66
CC	\$3.42	\$3.33

Sources: Brattle analysis of ISO-NE, Ventyx, and ICE data.

⁶³ We had not used 2018/2019 futures in the 2013 ORTP Study due to the thin volume, instead projecting 2018/2019 prices by extending 2014 futures out while maintaining a constant basis differential and market heat rate. As the ORTP objective was to generate a value for competitive entrants at the lower end of the spectrum, the higher electricity prices for 2018/2019 projected in the 2013 ORTP Study was appropriate.

D. Effect of PER and PFP on Revenue Offsets

Like E&AS margins, Peak Energy Rent (PER) deductions and Pay for Performance (PFP) payments will affect how much capacity revenue a resource would need to receive in the forward capacity auction in order to earn CONE in total. PER effectively takes away some of the E&AS margins, particularly during scarcity conditions. PFP provides an expected additional payment for well-performing new resources (or a penalty for poorer performers) during scarcity conditions. Thus, depending on the number of scarcity hours and other factors, PER tends to increase Net CONE and PFP slightly decreases it.

To estimate PER deductions and PFP payments, we assumed the New England market would experience 5.8 scarcity hours (H) in 2018/2019. That assumption is based on: (1) an analysis ISO-NE conducted as part of its evaluation of PFP, showing expected scarcity hours at criterion (*i.e.*, reserve margin = NICR) over a range of system conditions, as shown in Table 22;⁶⁴ and (2) considerations of consistency with 2018/2019 futures prices used to project E&AS margins. Although we considered larger H values from the ISO-NE analysis, stakeholders suggested that they would be inconsistent with the electricity prices that we are using in estimating E&AS margins. Indeed, the ICE futures prices for electricity and gas imply a declining market heat rate over time, as shown in Table 23. Declining market heat rates are hardly consistent with anticipating a large increase in scarcity hours, from the 3-hour recent historical average. It is possible that the futures prices understate future market heat rates as reserve margins decline, but it is nevertheless important for the PER deduction to be consistent with the futures prices used for the E&AS margin estimate.

Table 22
ISO-NE Analysis of Annual Expected Hours of System Operating Reserve Deficiencies at Criterion, Showing Sensitivity to Various Real-Time Demand Response (RTDR) and Tie Benefit Conditions

		<i>Amount of Tie Benefits Available Prior or Subsequent to Entering Reserve Deficiency Conditions</i>		
		All Prior	900 MW Prior	All Subsequent
<i>Amount of RTDR Available Prior or Subsequent to Entering Reserve Deficiency Conditions</i>	All Prior	5.8	10.9	21.2
	600 MW Subsequent	9.5	17.1	32.1

Sources: ISO-NE July 5 Memo.

⁶⁴ ISO-NE July 5, 2013 Memo to Markets Committee, Operating Reserve Deficiency Information – At Criteria And Extended Results. (“ISO-NE July 5Memo”). Available at: http://www.iso-ne.com/committees/comm_wkgrps/mrkt/mrkt/mrkt/mrkt/2013/jul10112013/a12a_iso_memo_07_05_13.pdf.

Table 23
Implied Market Heat Rates from Historical and ICE Forward Curves

Year	Gas (ACG)		On-Peak Electric (Mass Hub)		On-Peak MHR	
	\$/MMBtu		\$/MWh		Btu/kWh	
	Annual	July/Aug	Annual	July/Aug	Annual	July/Aug
Historical						
2010	\$5.32	\$4.93	\$56.35	\$72.45	10,598	14,709
2011	\$5.05	\$4.92	\$53.00	\$60.46	10,496	12,291
2012	\$3.96	\$3.62	\$41.67	\$49.59	10,511	13,688
2013	\$7.04	\$4.12	\$65.63	\$53.59	9,327	13,012
Futures (ICE)						
Bal. 2014	\$6.91	\$4.72	\$72.89	\$67.75	10,553	14,352
2015	\$7.47	\$4.37	\$71.84	\$58.65	9,614	13,409
2016	\$6.76	\$4.14	\$63.26	\$56.88	9,351	13,754
2017	\$6.33	\$4.25	\$53.58	\$50.33	8,465	11,838
2018	\$6.40	\$4.25	\$52.68	\$48.78	8,229	11,467
2019	\$6.51	\$4.38	\$54.08	\$52.53	8,304	12,002

Sources and notes: ICE futures were obtained from www.theice.com. See footnote 62 for more details. Implied market heat rates (MHR) calculated by dividing electricity prices by gas prices.

Therefore, we calculated the PER deduction from revenues for H equal to 5.8 for all candidate reference technologies. As shown in Table 24, we estimated the frequency of different types of scarcity event based on historical events and ISO-NE's analysis.⁶⁵ The total energy price is calculated for each scarcity event based on the assumption that the marginal price of energy is at the energy offer cap, while the Reserve Constraint Penalty Factor (RCPF) for operational scarcity events is based on the average RCPF during historical scarcity events in 2010 to 2012, with all other events based on the ISO-NE tariff.⁶⁶ The proxy unit strike price assumes Ultra Low Sulfur No. 2 Oil is the marginal fuel type with prices based on NYMEX futures and recent historical prices with heat rate and transportation mark-up from the ISO-NE tariff.⁶⁷ Finally, the scaling factor is assumed to be 1.0 for all scarcity events except operational scarcity, which is set to 0.75 based on the average value for such events from 2010 to 2012.⁶⁸

The PER calculation results in a reduction of revenue offsets for each candidate reference technology of \$0.43/kW-month, which correspondingly increases Net CONE.

⁶⁵ See ISO-NE July 5 Memo.

⁶⁶ See Tariff No. 3: Section III – Market Rule 1, III.2.7.A(c).

⁶⁷ See Tariff No. 3: Section III – Market Rule 1, III.13.7.2.7.1.1.1.

⁶⁸ The scaling factor in the PER deduction is defined as the load during scarcity events divided by the Summer 50/50 Peak System Load Forecast.

Table 24
Peak Energy Rent (PER) Calculation

Scarcity Event Type	Frequency of Scarcity	Marginal Price of Energy	Reserve Constraint Penalty Factor	Total Energy Price	Proxy Unit Strike Price	Scaling Factor	Total PER
	Event <i>hrs</i>	<i>\$/MWh</i>	<i>\$/MWh</i>	<i>\$/MWh</i>	<i>\$/MWh</i>		<i>\$/kW-mo</i>
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Operational Scarcity	3.190	\$1,000	\$575	\$1,575	\$519	0.748	\$0.20
Demand Response Called	0.692	\$1,000	\$0	\$1,000	\$519	1.000	\$0.03
System Thirty Minute Operating Reserve Depleted	1.154	\$1,000	\$500	\$1,500	\$519	1.000	\$0.09
Ten Minute Non-Spin	0.462	\$1,000	\$1,350	\$2,350	\$519	1.000	\$0.07
Ten Minute Spinning Depleted	0.308	\$1,000	\$1,400	\$2,400	\$519	1.000	\$0.05
						Total:	\$0.43

Sources and notes:

[1]: Analysis by Brattle based on information from ISO-NE July 5 Memo.

[2]: Assumed energy offer price cap in scarcity conditions.

[3]: Analysis by Brattle based on market rules in ISO-NE FERC Electric Tariff No. 3: Section III – Market Rule 1, III.2.7.A(c).

[4] = [2] + [3]

[5]: ISO-NE FERC Electric Tariff No. 3: Section III – Market Rule 1, III.13.7.2.7.1.1.1

[6] Analysis by Brattle.

[7] = [1] × ([4] - [5]) × [6] × Availability Factor of 0.95 / 1,000 kW per MW / 12 months per year.

To estimate the PFP payments, we also assumed the scarcity hours (H) to be 5.8, as shown in Table 25. We assumed a performance payment rate (PPR) of \$2,000 per MWh and the average actual performance (A) based on our assumed EFORD for each technology since the new resources are flexible enough to perform whenever they are not on outage.⁶⁹ We estimated the average balancing ratio as the average load plus operating reserves for the given H value divided by the net installed capacity requirement.

The PFP calculation results in payments for each candidate reference technology because they are assumed to perform well, with high availability and high flexibility. However, the estimated net financial impact on such units is small, at \$0.06/kW-month, which only slightly reduces Net CONE. The combined effect of PER and PFP will be a reduction in revenue offsets of \$0.37/kW-month and thus a similar increase in Net CONE.

⁶⁹ ISO-NE October 2, 2013 Memo to Markets Committee, FCM Pay for Performance – Revised Elements, p. 2. Available at: http://www.iso-ne.com/committees/comm_wkgrps/mrkt/mtrls/2013/oct892013/a03a_iso_memo_10_02_13.pdf.

Table 25
Pay for Performance (PFP) Calculation

Technology	Scarcity Hours <i>hrs</i> [1]	Performance Payment Rate <i>\$/MWh</i> [2]	Average Actual Performance <i>%</i> [3]	Average Balancing Ratio <i>%</i> [4]	Net Performance Payments <i>\$/kW-mo</i> [5]
Combined Cycle	5.8	\$2,000	98.0%	92.0%	\$0.06
Combustion Turbine	5.8	\$2,000	97.8%	92.0%	\$0.06

Sources and notes:

[1]: H, analysis by Brattle based on ISO-NE July 5, 2013 Memo to Markets Committee, Operating Reserve Deficiency Information – At Criteria And Extended Results.

[2]: PPR, ISO-NE October 2, 2013 Memo to Markets Committee, FCM Pay for Performance – Revised Elements, p. 2.

[3]: A, 1 – EFORD, based on value assumed for this analysis in Section IV.

[4]: BR, analysis by Brattle.

[5] = [1] × [2] × ([3] – [4]) / 1,000 kW per MW / 12 months per year.

E. Summary of Revenue Offsets

Based on the calculations of E&AS margins and the net impact of PER and PFP discussed in this section, a summary of revenue offsets for the candidate reference technologies is shown in Table 26.

Table 26
Candidate Reference Technology Revenue Offset Summary

Reference Technology	E&AS Margin <i>\$/kW-mo</i>	PFP/ PER <i>\$/kW-mo</i>	Revenue Offset <i>\$/kW-mo</i>
LM6000	\$1.67	-\$0.37	\$1.30
LMS100	\$1.69	-\$0.37	\$1.32
Frame CT	\$1.66	-\$0.37	\$1.29
CC	\$3.33	-\$0.37	\$2.96

Source: Brattle analysis.

IX. SUMMARY OF NET CONE RESULTS

The Net CONE is calculated as the annual average revenues required for entry in the first year, or CONE, minus the first year revenue offsets. A summary of the Net CONE for each candidate reference technology is shown in Table 27.

Table 27
Candidate Reference Technology Net CONE Summary (2018\$)

Reference Technology	Installed Capacity	Overnight Cost	Capital Costs	Fixed O&M	Gross CONE	E&AS Offsets	PER/PFP Offsets	Net CONE
<i>Rest of Pool</i>	<i>MW</i>	<i>\$/kW</i>	<i>\$/kW-mo</i>	<i>\$/kW-mo</i>	<i>\$/kW-mo</i>	<i>\$/kW-mo</i>	<i>\$/kW-mo</i>	<i>\$/kW-mo</i>
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
4x0 LM6000	173	\$1,965	\$17.91	\$3.26	\$21.18	\$1.67	-\$0.37	\$19.88
2x0 LMS100	188	\$1,711	\$15.60	\$2.85	\$18.45	\$1.69	-\$0.37	\$17.13
2x0 Frame CT	417	\$902	\$8.21	\$1.55	\$9.76	\$1.66	-\$0.37	\$8.47
2x1 CC	715	\$1,178	\$11.59	\$2.44	\$14.04	\$3.33	-\$0.37	\$11.08

Notes:

[1]: See Table 8 in Section IV.

[2]: Escalated to 2018 dollars from values in Table 13 in Section V.

[3]: See Table 18 in Section VII.

[4]: Escalated to 2018 dollars from values in Table 14 in Section VI.

[5] = [3] + [4].

[6], [7]: See Table 26 in Section VIII.

[8] = [5] - ([6] + [7]).

X. RECOMMENDED NET CONE FOR THE DEMAND CURVE

A. Recommended Reference Technology

We recommend a CC as the reference technology because we are most confident that our estimate of its Net CONE accurately reflects the true cost of competitive merchant entry into the ISO-NE Forward Capacity Market. CC plants are the predominant generation technology being developed by merchant developers throughout the U.S., including the one merchant project (Footprint Power's Salem Harbor plant) that has cleared recently in ISO-NE's Forward Capacity Market. As such, we are more confident that merchant developers will build CCs as a part of the long-term equilibrium mix in New England than other technologies, and setting demand curve prices according to the CC Net CONE should procure the amount of capacity needed to meet reserve margin objectives. Importantly for reference technology selection, the prevalence of CC development in recent years has produced quite standardized plant configurations and prices that facilitate more accurate cost estimates than other technologies. Estimation of the E&AS margins is still inherently uncertain, but we find that the uncertainty is similar, if not greater, for combustion turbines in New England with their reliance on ancillary services markets, especially the Forward Reserve Market, that have been both thin and volatile over the past several years.

We ruled out the aeroderivative combustion turbines (LMS100 and LM6000) as the reference technology because they are rarely built by merchant developers (see discussion of Table 2 in Section III above) and their estimated Net CONEs are significantly (>50%) higher than the CC Net CONE. With little merchant activity, the aeroderivative CTs do not

currently appear to be economic for merchant developers to build in New England. With so little construction even by non-merchant generators, the few projects that do exist have had highly non-standard pricing.⁷⁰ Turbine manufacturers have offered developers various discounts whose continuation is difficult to predict accurately.⁷¹ Our estimated aeroderivative CT Net CONE is much higher than for the CC, and we do not believe resource adequacy in New England will depend on the entry of such costly units in the coming years.

We could have chosen a Frame CT as the reference technology, as it meets most of the principles outlined for the ISO-NE FCM and is a viable technology that has been demonstrated by the Marsh Landing plant in California to meet NO_x environmental standards with an SCR.⁷² It serves as the reference technology for PJM's and NYISO's demand curves. However, ISO-NE does not share their tariff specifications that point to combustion turbines as the reference technology. Nor does ISO-NE have a precedent of selecting a Frame CT (or any technology) as a reference for sloped demand curves. As ISO-NE now introduces its own sloped demand curve, we believe the CC is a better reference technology for New England than the CT. Our rationale for not selecting the Frame CT is the combination of two factors: the Frame CT has the lowest estimated Net CONE of all the technologies we evaluated in New England; and yet it is not being constructed by merchant generators in New England nor in other capacity market RTOs. If the Frame CT's lack of entry indicates that its *true* Net CONE exceeds our estimate for any reason,⁷³ selecting it as the reference technology would set the demand curve prices too low. Administrative Net CONE would be below the true Net CONE of all technologies evaluated, resulting in likely under-procurement. Our concern about this possibility is accentuated by the simulation analysis described in the Newell/Spees Testimony, which showed significant reliability consequences of under-procuring capacity due to under-estimating Net CONE versus modest cost consequences of over-estimating Net CONE.

The risk of under-procurement may be greater in New England than in other RTO markets due to its lack of history of attracting merchant entry since implementing the FCM. Undoubtedly, the main barrier to entry has been the existing capacity surplus since before FCM's inception. However, the FCM has also been affected by administrative pricing rules and state intervention that some investors assert weakens their view of the market even as market fundamentals tighten. Investors also express concern about the region's low rate of load growth, which risks producing long periods of prices not being set by new entrants, and the relatively small size of the market, which makes prices more sensitive to shifts in supply.

⁷⁰ As shown above in Table 2, there is currently 1,300 MW of aeroderivative CT development versus 76,800 MW of CC in development across the U.S.

⁷¹ See further explanation in Section V.D.

⁷² The testimony attesting to the economic viability can be found in Before the Federal Energy Regulatory Commission, Docket No. ER14-500-000, *Affidavit of Marc W. Chupka*, November 27, 2013. The Commission's order accepting it can be found in the FERC NYISO Order.

⁷³ One possible explanation of the lack of merchant development of frame-type CTs is that the SCR technology was proven only very recently, and developers will begin building them soon. It is also possible that the frame-type CT is not as economic as CCs in the regions where significant merchant generation is being added (especially PJM and ERCOT). But it is also possible that we have understated its risks or costs; or we have overstated its long-term prospects relative to CCs (*e.g.*, if developers expect gas prices to rise and/or expect future CCs to capture some of the ancillary services revenues CTs depend on), which could make it need more than level-real CONE in its first several years in order to enter.

ISO-NE is implementing a demand curve and proposing a 7-year price lock-in option for new entrants to mitigate these concerns, but the proof will be whether the FCM can attract merchant entry over the next several years as PJM and NYISO have enjoyed through their capacity markets.

Within this context of market uncertainty and merchant risk, we believe that relying on the dominant CC as the reference technology is the best option for procuring adequate resources and successfully launching the new FCM market design. We are most confident that merchant generators will build CCs, and we are most confident in our Net CONE estimate for the CC reference technology.

Section III explained that averaging the Net CONE of more than one technology that meets the reference technology principles may provide a more stable and efficient basis for setting Net CONE on the demand curve than using the Net CONE of a single technology. For now though, relying on only the CC is more prudent for the reasons described above. However, if merchant developers introduce frame-type turbines to New England over the next several years, ISO-NE should consider averaging its Net CONE together with that of a CC.

As market activity and technology evolve, we recommend that ISO-NE revisit the choice of reference technologies during future Net CONE studies by following the considerations we outlined in Section III.C.2. One of the considerations we emphasized is to avoid frequently switching reference technologies based on changes in relative Net CONE estimates that could be due to estimation error or transient market conditions, but this does not preclude prudently revisiting the choice of reference technologies over time.

B. Recommended Net CONE

Based on our analysis contained in this testimony, we recommend that ISO-NE set the Net CONE parameter in the sloped demand curve for FCA9 to \$11.08/kW-month.

XI. LOCATIONAL NET CONE

The analysis in this testimony focuses on estimating a Rest of Pool (ROP) Net CONE as ISO-NE is proposing to introduce a sloped demand curve for FCA9 solely in the ROP capacity zone. We also completed a high-level analysis of how the CC Net CONE value would differ in the ISO-NE import-constrained zones of Northeast Massachusetts/Boston (NEMA/Boston) to identify whether a separate Net CONE should be used for administrative pricing in the years prior to establishing a sloped demand curve. We found that the differences are insignificant and recommend using the system-wide value throughout ISO-NE. In addition, the system-wide value should be suitable for the local zones when ISO-NE develops zonal demand curves for FCA10 and FCA11.

A. Approach

Using the labor rates developed to choose the location of the reference technologies in ROP (see Section IV.B), we selected the NEMA/Boston location. We made no changes in the technical specifications of reference technologies as the environmental regulations and ambient conditions are not significantly different compared to Worcester County,

Massachusetts. We adjusted the capital and fixed O&M cost estimates based on the labor rates, land prices, and property taxes in that area. Due to limited congestion between these areas within New England, we did not adapt the estimated revenue offsets for these capacity zones.

B. NEMA/Boston

We chose to locate the reference technologies in Lowell, Massachusetts for NEMA/Boston as their labor rates were representative of the capacity zone region while avoiding the areas with very high rates closer to Boston. The labor rates in our analysis are approximately 20% higher in Lowell than Worcester. In addition, we found that leasing costs were higher by \$6,000 per acre per year. A review of PILOT agreements in close proximity to Lowell did not provide any justification for adjusting the tax assumptions used for Worcester. Table 28 shows the impact of higher labor and land costs on CC Net CONE. The difference from the ROP value is less than 2%.

Table 28
Comparison of CC Net CONE for ROP and NEMA/Boston

Capacity Zone	Installed Capacity MW	Total Plant Capital Cost \$m	Overnight Cost \$/kW	After-Tax WACC %	Capital Costs \$/kW-mo	Fixed O&M \$/kW-mo	Gross CONE \$/kW-mo	E&AS Offsets \$/kW-mo	PER/PFP Offsets \$/kW-mo	Net CONE \$/kW-mo
ROP	715	\$900	\$1,178	8.0%	\$11.59	\$2.44	\$14.04	\$3.33	-\$0.37	\$11.08
NEMA/Boston	715	\$910	\$1,192	8.0%	\$11.73	\$2.50	\$14.23	\$3.33	-\$0.37	\$11.27

Source: Brattle and S&L analysis.

C. Connecticut

As Net CONE in NEMA/Boston was found to be insignificantly different from the ROP value and labor rates in Connecticut are closer to those in ROP, we concluded that Net CONE in Connecticut would be very close to the ROP value.

XII. ANNUAL UPDATE PROCESS

For FCA10 and FCA11, ISO-NE can update the Net CONE parameter by escalating the cost components and revenues offsets developed for FCA9 according to the indices recommended below. A full re-evaluation of the Net CONE parameter is recommended for FCA12.

A. Indices for Capital and Fixed O&M Costs

As different cost items are expected to rise at different rates, we proposed cost indices appropriate for each cost component so that future Net CONE values can be formulaically derived and provide relatively accurate capital costs and fixed O&M costs. As shown in Table 29 below, we relied on publicly available indices such as the Producer Price Index (PPI) and the Quarterly Census of Employment and Wages (QCEW) published by the Bureau of Labor Statistics. The PPI indices measure the average change over time in the selling prices received by domestic producers for their outputs, and therefore should reflect

the increase/decrease in capital investment and O&M costs for a different commercial online year.⁷⁴ The QCEW indices are developed from a quarterly count of employment and wages reported by employers covering 98% of U.S. jobs, available at the county, state, and national levels by industry.⁷⁵

As of the date when our estimates for FCA9 were developed, the PPI indices are available through February 2014 and the QCEW indices through 2012. When ISO-NE updates Net CONE for the upcoming FCAs, indices covering the most recent 12 months at that time will be compared against the current values to derive the appropriate escalation rates. The full description of each index is available in the 2014 Net CONE Capital Budgeting Model submitted with this report.

Table 29
Indices Applied to Various Cost Components

Cost Component	Index
Capital Costs	
Gas Turbines	BLS-PPI "Turbines and Turbine Generator Sets"
Steam Turbines	BLS-PPI "Turbines and Turbine Generator Sets"
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, Worcester County, MA
Other Labor	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay, Worcester County, MA
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)"
Fixed O&M Costs	
Labor, Administrative and General	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay, Worcester County, MA
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)"

Sources and Notes: Bureau of Labor Statistics ("BLS") Producer Price Index ("PPI") from BLS, 2013a and Quarterly Census of Employment and Wages from BLS, 2013b.

B. Updates on Revenue Offsets

For ISO-NE to update the E&AS margins for FCA 10 and 11, Mass Hub On-Peak futures will need to be updated through the commitment periods by accessing the ICE website. The PER and PFP offsets should be revisited if the market rules change, but otherwise our current estimates can be used until the next Net CONE study.

⁷⁴ Bureau of Labor Statistics, *Producer Price Index*. (BLS, 2013a) Available at: <http://www.bls.gov/ppi/>.

⁷⁵ Bureau of Labor Statistics, *Quarterly Census of Employment and Wages*. (BLS, 2013b) Available at <http://www.bls.gov/cew/>.

XIII. CERTIFICATION

We hereby certify that we have read the filing signed and know its contents are true as stated to the best of our knowledge and belief. We possess full power and authority to sign this filing.

Respectfully Submitted,



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Dr. Samuel Newell's expertise is in the analysis and modeling of electricity markets, the transmission system, and RTO rules. He supports clients in regulatory, litigation, and business strategy matters involving wholesale market design, contract disputes, generation asset valuation and development, benefit-cost analysis of transmission enhancements, the development of demand response programs, and integrated resource planning. He frequently provides testimony and expert reports to RTOs, state regulatory commissions, and the FERC and has testified before the American Arbitration Association.

Dr. Newell earned a Ph.D. in technology management and policy from the Massachusetts Institute of Technology, an M.S. in materials science and engineering from Stanford University, and a B.A. in chemistry and physics from Harvard College.

AREAS OF EXPERTISE

- Electricity Wholesale Market Design
- Valuation of Generation Assets
- Energy Litigation
- Integrated Resource Planning
- Evaluation of Demand Response (DR)
- Transmission Planning and Modeling
- RTO Participation and Configuration
- Analysis of Market Power
- Tariff and Rate Design
- Business Strategy

EXPERIENCE

Electricity Market Wholesale Design

- **Market Development Vision.** For the Midcontinent Independent System Operator (MISO), worked with MISO staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2-5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities for improving MISO's electricity market; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- **Economically Optimal Reserve Margins.** For the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT), co-authored a report estimating the economically-optimal reserve margin. Compared to various

SAMUEL A. NEWELL

reliability-based reserve margins, and evaluated the cost and uncertainty of energy-only and a potential capacity market in ERCOT. Conducted the study in collaboration with Astrape Consulting to construct a series of economic and reliability modeling simulations that account for uncertain weather patterns, generation and transmission outages, and multi-year load forecasting errors. The simulations also incorporate detailed representation of the Texas power market, including intermittent wind and solar generation, operating reserves, different types of demand response, the full range of emergency procedures (such as operating reserve deletion), scarcity pricing provisions, and load-shed events.

- **Offer Review Trigger Prices in ISO-NE.** For the Internal Market Monitor in ISO New England, developed offer review trigger prices for screening for uncompetitively low offers in the Forward Capacity Market. Collaborated with Sargent & Lundy to conduct a bottom-up analysis of the costs of building and operating gas-fired generation technologies and onshore wind; also estimated the costs of energy efficiency, and demand response. For each technology, estimated the capacity payment needed to make the resource economically viable, given expected non-capacity revenues, a long-term market view, and a cost of capital. Recommendations were filed with and accepted by the Federal Energy Regulatory Commission (FERC).
- **Evaluation of Investment Incentives and Resource Adequacy in ERCOT.** For the Electric Reliability Council of Texas (ERCOT), led a team that (1) characterized the factors influencing generation investment decisions; (2) evaluated the energy market's ability to support investment and resource adequacy at the target level; and (3) evaluated options to enhance long-term resource adequacy while maintaining market efficiency. Conducted the study by performing forward-looking simulation analyses of prices, investment costs, and reliability. Interviewed a broad spectrum of stakeholders; worked with ERCOT staff to understand the relevant aspects of their planning process, operations, and market data. Findings and recommendations became a launching point for a PUCT Proceeding, in which I filed comments and presented at several workshops between June 2012 and July 2013.
- **Second Triennial Review of PJM Capacity Market and CONE Study.** For PJM, conducted second tri-annual review of the Reliability Pricing Model. Analyzed capacity auction results and response to market fundamentals. Interviewed stakeholders and documented concerns. Addressed key market design elements and recommended improvements to reduce pricing uncertainty and safeguard future performance. Led a study of the Cost of New Entry (CONE), based on detailed engineering estimates developed by EPC contractor CH2M HILL, for use in PJM's setting of auction parameters. Served as PJM's witness in filing CONE values and a Settlement Agreement.

SAMUEL A. NEWELL

- **Evaluation of Reliability Pricing Model (RPM) Results and Design Elements.** For PJM, co-led a detailed review of the performance of its forward capacity market. Reviewed the results of the first five forward auctions for capacity. Concluded that the auctions were working and demonstrated success in attracting and retaining capacity, but made more than thirty design recommendations. Recommendations addressed ways to remove barriers to participation, ensuring adequate compensation/penalties, and improving the efficiency of the market. Resulting whitepaper was submitted to the FERC and presented to PJM stakeholders.
- **Evaluation of ISO-NE Forward Capacity Market (FCM) Results and Design Elements.** With the ISO-NE market monitoring unit, reviewed the performance of the first two forward auctions in ISO-NE's FCM. Evaluated key design elements regarding demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, the use of the Cost of New Entry in auction parameters, and whether to have an auction price ceiling and floor. Resulting whitepaper filed with the FERC and presented to ISO-NE stakeholders.
- **Evaluation of a Potential Forward Capacity Market in NYISO.** For NYISO, conducted a benefit-cost analysis of replacing its existing short-term ICAP market structure with a proposed four-year forward capacity market (FCM) design. Evaluation based on stakeholder interviews, the experience of PJM and ISO-NE with their forward capacity markets, and review of the economic literature regarding forward capacity markets. Addressed the following attributes of FCM relative to the existing market: risks to buyers and suppliers, mitigation of market power, implementation costs, and long-run costs. Recommendations used by NYISO and stakeholders to help decide whether to pursue a forward capacity market.
- **RTO Accommodation of Demand Response (DR) for Resource Adequacy.** For MISO, helped modify its tariff and business practices to accommodate DR in its resource adequacy construct by defining appropriate participation rules. Informed design by surveying in detail the practices of other RTOs, and by characterizing the DR resources within the MISO footprint.
- **Integration of DR into ISO-NE's Energy Markets.** For ISO-NE, provided analysis and assisted with a stakeholder process to develop economic DR programs to replace the current economic DR programs when they expire in 2010.
- **Integration of DR into MISO's Energy Markets.** For MISO, wrote a whitepaper evaluating the available approaches to incorporating economic DR in energy markets. Assessed the efficiency and the "realistic achievable potential" for each approach. Identified implementation barriers at the state and RTO levels.

SAMUEL A. NEWELL

Recommended changes to business rules to efficiently accommodate curtailment service providers (CSPs).

- **MISO Capacity Market Enhancements.** Supported MISO in developing market design elements for its proposed annual locational capacity auctions.
- **Evaluation of MISO's Resource Adequacy Construct and Market Design Elements.** For MISO, conducted the first major assessment of its new resource adequacy construct. Identified several major successes and a series of recommendations for improvement in the areas of load forecasting, locational resource adequacy, and determination of the target level of reliability. The report incorporates extensive stakeholder input and review, and comparisons to other ISOs' capacity market designs. Continued to consult with MISO in its work with the Supply Adequacy Working Group on design improvements.
- **Evaluation of MISO's Demand Response Integration.** For MISO, conducted an independent assessment of its progress in integrating DR into its resource adequacy, energy, and ancillary services markets. Analyzed market participation barriers to date. Assessed the likelihood of MISO's "ARC Proposal" to eliminate barriers to participation by curtailment service providers. Made recommendations for potential further improvements to market design elements.
- **Evaluation of Tie-Benefits.** For ISO-NE, analyzed the implications of different levels of tie-benefits (i.e., assistance from neighbors, allowing reductions in installed capacity margins) on capacity costs, emergency procurement costs, capacity prices, and energy prices. Resulting whitepaper submitted by ISO-NE to the FERC in its filing on tie-benefits.
- **Evaluation of Major Initiatives.** With ISO-NE and its stakeholders, developed criteria for identifying "major" market and planning initiatives that trigger the need for the ISO to provide qualitative and quantitative information to help stakeholders evaluate the initiative, as required in ISO-NE's tariff. Also developed guidelines on the kinds of information ISO-NE should provide for major initiatives.
- **LMP Impacts on Contracts.** For a West Coast client, critically reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed implications for "seller's choice" supply contracts. Developed a framework for quantifying the incremental congestion costs that ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated potential incremental contract costs using a third party's GE-MAPS market simulations (and helped to improve their model inputs to more accurately reflect the transmission system in California). Applied findings to support the ISO in design modifications of the California market under LMP.
- **RTO Accommodation of Retail Access.** For MISO, made recommendations for improving business practices in order to facilitate retail access (and to enable auctions for the supply of regulated generation service). Analyzed the retail access

SAMUEL A. NEWELL

programs in the three restructured states within MISO -- Illinois, Michigan, and Ohio. Performed a detailed study of retail accommodation practices in other RTOs, focusing on how they have modified their procedures surrounding transmission access, qualification of capacity resources, capacity markets, FTR allocations, and settlement.

Valuation of Generation Assets and Contracts

- **Valuation Methodology for a Coal Plant Transaction in PJM.** For a part owner of a very large coal plant being transferred at an assessed value that was yet to be determined by a third party, wrote a manual describing how to conduct a market valuation of the plant. Addressed drivers of energy and capacity value; worked with an engineering subcontractor to describe how to determine the remaining life of the plant and CapEx needs going forward. Our manual was used to inform their pre-assessment negotiation strategy.
- **Valuation of a Coal Plant in PJM.** For the lender to a bidder on a coal plant being auctioned, estimated the market value of the plant. Valuation analysis focused especially on the effects of coal and gas prices on cash flows, and the ongoing fixed O&M costs and CapEx needs of the plant.
- **Valuation of a Coal Plant in New England.** For a utility, evaluated a coal plant's economic viability and market value. Analysis focused on projected market revenues, operating costs, and capital investments likely needed to comply with future environmental mandates.
- **Valuation of Generation Assets in New England.** To inform several potential buyers' valuations of various assets being sold in ISO-NE, provided energy and capacity price forecasts and cash flows under multiple scenarios. Explained the market rules and fundamentals to assess key risks to cash flows.
- **Valuation of Generation Asset Bundle in New England.** For the lender to the potential buyer of generation assets, provided long-term energy and capacity price forecasts, with multiple scenarios to test whether the plant could be worth less than the debt. Reviewed a broad scope of documents available in the "data room" to identify market, operational, and fuel supply risks.
- **Valuation of Generation Asset Bundle in PJM.** For a major retail energy provider preparing to bid for a bundle of generation assets, provided energy and capacity price forecasts and reviewed their valuation methodology. Analyzed the supply and demand fundamentals of the PJM capacity market. Performed locational market simulations using the Dayzer model to project nodal prices as market fundamentals evolve. Reviewed the client's spark spread options model.

SAMUEL A. NEWELL

- **Wind Power Development.** For a developer proposing to build a several hundred megawatt wind farm in Michigan provided a market-based revenue forecast for energy and capacity. Identified gas and CO₂ allowance prices as the key drivers of revenue uncertainty, and evaluated the implications of several detailed scenarios around these variables.
- **Wind Power Financial Modeling.** For an offshore wind developer proposing to build a 350 MW project in PJM off the coast of New Jersey, analyzed market prices for energy, renewable energy certificates, and capacity. Provided a detailed financial model of project funding and cash distributions to various types of investors (including production tax credit). Resulting financial statements were used in an application to the state of New Jersey for project grants.
- **Contract Review for Cogeneration Plant.** For the owner of a large cogeneration plant in PJM, conducted an analysis of revenues under the terms of a long-term PPA (in renegotiation) vs. potential merchant revenues. Accounted for multiple operating modes of the plant and its sales of energy, capacity, ancillary services, and steam over time.
- **Generation Strategy/Valuation.** For an independent power producer, acted for over two years as a key advisor on the implementation of the client's growth strategy. Led a large analytical team to assess the profitability of proposed new power plants and acquisitions of portfolios of plants throughout the U.S. Used the GE-MAPS market simulation model to forecast power prices, transmission congestion, generator dispatch, emissions costs, energy margins for candidate plants; used an ancillary model to forecast capacity value.
- **Generation Asset Valuation.** For multiple banks and energy companies, provided valuations of financially distressed generating assets. Used GE-MAPS to simulate net energy revenues; a capacity model to estimate capacity revenues; and a financial valuation model to value several natural gas, coal, and nuclear power plants across a range of plausible scenarios. Identified key uncertainties and risks in the acquisition of such assets.

Energy Litigation

- **Demand Response Arbitration.** Provided expert testimony on behalf of a client that had acquired a demand response company and alleged that the company had overstated its demand response capacity and technical capabilities. Analyzed discovery materials including detailed demand response data to assess the magnitude of alleged overstatements. Calculated damages primarily based on a fair market valuation of the company with and without alleged overstatements. Provided deposition, expert report, and oral testimony in arbitration before the American Arbitration Association (non-public).

SAMUEL A. NEWELL

- **Contract Damages.** For the California Department of Water Resources and the California Attorney General's office, supported expert providing testimony on damages resulting from an electricity supplier's breaches of a power purchase agreement. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration. Resulted in successful award for client.
- **Contract Damages.** For the same client and contract described above, supported expert providing testimony in arbitration regarding the supplier's alleged breaches in which its scheduled deliveries were not deliverable due to transmission congestion. Quantified damages and demonstrated the predictability of congestion, which the supplier was allegedly supposed to avoid in its choice of delivery points.
- **Contract Termination Payment.** For an independent power producer, supported expert testimony on damages resulting from the termination of a long-term tolling contract for a gas-fired power plant in PJM, involving power market forecasting, financial valuation techniques, and a detailed assessment of the plant's operating characteristics and costs. Prepared witness for arbitration and assisted counsel in deposing and cross-examining opposing experts. Resulted in resounding victory for client.

Integrated Resource Planning (IRP)

- **IRP in Connecticut (for the 2008, 2009, 2010, 2012, and 2014 Plans).** For the two major utilities in Connecticut and The Connecticut Department of Energy and Environmental Protection (DEEP), helped lead the analysis for five successive integrated resource plans. Plans included projecting ten-year Base Case outlooks for resource adequacy, customer costs, emissions, and RPS compliance; developing plausible alternative scenarios driven by exogenous market factors; and evaluating resource procurement strategies focused on energy efficiency, renewables, and more traditional sources. Used an integrated modeling system that simulated the New England locational energy market (with the DAYZER model), the forward capacity market, and REC markets, and suppliers' likely investment/retirement decisions. Addressed key policy questions regarding supply risks, RPS standards, environmental regulations, transmission planning, emerging technologies, and energy security. Solicited input from stakeholders. Provided oral testimony before the DEEP.
- **Contingency Plan for Indian Point Nuclear Retirement.** For the New York Department of Public Service (DPS), assisted in developing contingency plans for maintaining reliability if the Indian Point nuclear plant were to retire. Evaluated generation and transmission proposals along three dimensions: their reliability

SAMUEL A. NEWELL

contribution, viability for completion by 2016, and the net present value of costs. The work involved partnering with engineering sub-contractors, running GE-MAPS and a capacity market model, and providing insights to DPS staff.

- **Analysis of Potential Retirements to Inform Transmission Planning.** For a large utility in Eastern PJM, analyzed the potential economic retirement of each coal unit in PJM under a range of scenarios regarding climate legislation, legislation requiring mercury controls, and various capacity price trajectories.
- **Resource Planning in Wisconsin.** For a utility considering constructing new capacity, demonstrated the need to consider locational marginal pricing, gas price uncertainty, and potential CO₂ liabilities. Guided client to look beyond building a large coal plant. Led them to mitigate exposures, preserve options, and achieve nearly the lowest expected cost by pursuing a series of smaller projects, including a promising cogeneration application at a location with persistently high LMPs. Conducted interviews and facilitated discussions with senior executives to help the client gain support internally and begin to prepare for regulatory communications.

Evaluation of Demand Response (DR)

- **DR Potential Study.** For an ISO, analyzed the biggest, most cost-effective opportunities for DR and price responsive demand in the footprint, and what the ISO could do to facilitate them. For each segment of the market, identified the ISO and/or state and utility initiatives that would be needed to develop various levels of capacity and energy market response. Also estimated the potential and cost characteristics for each segment. Interviewed numerous curtailment service providers and ISO personnel.
- **Evaluation of DR Compensation Options.** For ISO-NE, analyzed the implications of various DR compensation options on consumption patterns, LMPs, capacity prices, consumer surplus, producer surplus, and economic efficiency. Presented findings in a whitepaper that ISO-NE submitted to FERC.
- **Wholesale Market Impacts of Price Responsive Demand (PRD).** For NYISO, evaluated the potential effects of widespread implementation of dynamic retail rates. Utilized the PRISM model to estimate effects on consumption by customer class, applied empirically-based elasticities to hourly differences between flat retail rates and projected dynamic retail rates. Utilized the DAYZER model to estimate the effects of load changes on energy costs and prices.
- **Energy Market Impacts of DR.** For PJM and the Mid-Atlantic Distributed Resources Initiative (sponsored by five state commissions), quantified the market impacts and customer benefits of DR programs. Used a simulation-based approach to quantify the impact that a three percent reduction of peak loads during the top 20 five-hour blocks would have had in 2005 and under a variety of alternative

SAMUEL A. NEWELL

market conditions. Utilized the DAYZER market simulation model, which we calibrated to represent the PJM market using data provided by PJM and public sources. Results were presented in multiple forums and cited widely, including by several utilities in their filings with state commissions regarding investment in advanced metering infrastructure and implementation of DR programs.

- **Present Value of DR Investments.** For Pepco Holdings, Inc., analyzed the net present value of its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated the reductions in peak load that would be realized from dynamic pricing, direct load control, and efficiency. Built on the Brattle-PJM-MADRI study to estimate the short-term energy market price impact and addressed the long-run equilibrium offsetting effects through several plausible supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Documented findings in a whitepaper submitted to DE, NJ, MD, and DC commissions. Presented findings to DE Commission.

Transmission Planning and Modeling

- **Benefits of New 765kV Transmission Line.** For a utility joint venture between AEP and ComEd, analyzed renewable integration and congestion relief benefits of their proposed \$1.2 billion RITELine project in western PJM. Guided client staff to conduct simulations using PROMOD. Submitted testimony to FERC.
- **Benefit-Cost Analysis of a Major Transmission Project for Offshore Wind.** Submitted testimony on the economic benefits of the Atlantic Wind Connection Project, a proposed 2,000 MW DC offshore backbone from New Jersey to Virginia with 7 onshore landing points. Described and quantified the effects of the Project on congestion, capacity markets, CO₂ emissions, system reliability and operations, jobs and economic stimulus, and the installed cost of offshore wind generation. Directed Ventyx staff to simulate the congestion, production cost, and LMP impacts using the PROMOD model.
- **Analysis of Transmission Congestion and Benefits.** Analyzed the impacts on transmission congestion, and customer benefits in California and Arizona of a proposed inter-state transmission line. Used the DAYZER model to simulate congestion and power market conditions in the Western Electricity Coordination Council region in 2013 and 2020 considering increased renewable generation requirements and likely changes to market fundamentals.
- **Benefit-Cost Analysis of New Transmission.** For a transmission developer's application before the California Public Utility Commission (CPUC) to build a new 500 kV line, analyzed the benefits to ratepayers. Analysis included benefits beyond those captured in a production cost model, including the benefits of integrating a

SAMUEL A. NEWELL

pumped storage facility that would allow the system to accommodate a larger amount of intermittent renewable resources at a reduced cost.

- **Benefit-Cost Analysis of New Transmission in the Midwest.** For the American Transmission Company (ATC), supported Brattle witness evaluating the benefits of a proposed new 345 kV line (Paddock-Rockdale). Advised client on its use of PROMOD IV simulations to quantify energy benefits, and developed metrics to properly account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer costs. Developed and applied new methodologies for analyzing benefits not quantified in PROMOD IV, including competitiveness, long-run resource cost advantages, reliability, and emissions. Testimony was submitted to the Public Service Commission of Wisconsin, which approved the line.
- **Transmission Investments and Congestion.** Worked with executives and board of an independent transmission company to develop a “metric” indicating access and congestion-related benefits provided by its transmission investments and operations.
- **Analysis of Transmission Constraints and Solutions.** For a large, geographically diverse group of clients, performed an in-depth study identifying the major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions to the bottlenecks. Worked with transmission engineers from multiple organizations to refine the data in a load flow model and a security-constrained, unit commitment and dispatch model for each interconnection. Ran 12-year, LMP-based market simulations using GE-MAPS across multiple scenarios and quantified congestion costs on major constraints. Collaborated with engineers to design potential transmission (and generation) solutions. Evaluated the benefits and costs of candidate solutions and identified several highly economic major transmission projects.
- **Merchant Transmission Impacts.** For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices in Connecticut and Long Island.
- **Security-Constrained Unit Commitment and Dispatch Model Calibration.** For a Midwestern utility, calibrated their PROMOD IV model, focusing on LMPs, unit commitment, flows, and transmission constraints. Helped client to understand their model’s shortcomings and identify improvement opportunities. Also assisted with initial assessments of FTRs in preparation for its submission of nominations in MISO’s first allocation of FTRs.
- **Model Evaluation.** Led an internal Brattle effort to evaluate commercially available transmission and market simulation models. Interviewed vendors and users of PROMOD IV, Gridview, DAYZER, and Henwood LMP. Performed intensive in-house testing of each model. Evaluated accuracy of model algorithms (e.g., LMP,

losses, unit commitment) and ability and ease to calibrate models with backcasts using actual RTO data.

RTO Participation and Configuration

- **Market Impacts of RTO Seams.** For a consortium of utilities, submitted written testimony to the FERC analyzing the financial and operational impact of the MISO-PJM seam on Michigan and Wisconsin. Evaluated economic hurdles across regional transmission organization (RTO) seams and assessed the effectiveness of inter-RTO coordination efforts underway. Collaborated with MISO staff to leverage their PROMOD IV model to simulate electricity markets under alternative RTO configurations.
- **Analysis of RTO Seams.** For a Wisconsin utility in a complaint proceeding before the FERC, assisted expert witness providing testimony regarding (1) the inadequacy of MISO and PJM's current efforts to improve inter-RTO coordination, and (2) the large net economic benefit of implementing a full joint-and-common market. Analyzed lack of convergence between MISO and PJM in energy prices and in shadow prices of reciprocal coordinated flow gates. Analyzed results of MISO and PJM's market simulation models.
- **RTO Participation.** For an integrated Midwest utility, advised client on alternative RTO choices. Used GE-MAPS to model the transmission system and wholesale markets under various scenarios. Presented findings to senior management. Subsequently, in support of testimonies submitted to two state commissions, quantified the benefits and costs of RTO membership on customers, considering energy costs, FTR revenues, and wheeling revenues.

Analysis of Market Power

- **Buyer Market Power.** On Behalf of the "Competitive Markets Coalition" group of generating companies, helped develop and evaluate various proposals for improving PJM's Minimum Offer Price Rule so that it more effectively protects the capacity market from manipulation by buyers while reducing interference with non-manipulative activity. Participated in discussions with other stakeholders. Submitted testimony to FERC supporting tariff revisions that PJM filed.
- **Vertical Market Power.** Before the NYPSC, examined whether the merger between National Grid and KeySpan potentially created incentives to exercise vertical wholesale market power. Employed a simulation-based approach using the DAYZER model of the NYISO wholesale power market and examined whether outages of National Grid's transmission assets significantly affected KeySpan's generation profits.

SAMUEL A. NEWELL

- **Market Monitoring and Market Power Mitigation.** For the PJM Interconnection, assessed their market mitigation practices and co-authored a whitepaper “Review of PJM’s Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets” (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes, and others).

Tariff and Rate Design

- **Transmission Tariffs.** For a merchant generating company participating in FERC hearings on developing a Long Term Transmission Pricing Structure, helped lead a coalition of stakeholders to develop a position on how to eliminate pancaked transmission rates while allowing transmission owners to continue to earn their allowed rate of return. Analyzed and presented the implications of various transmission pricing proposals on system efficiency, incentives for new investment, and customer rates throughout the MISO-PJM footprint.
- **Retail Rate Riders.** For a traditionally regulated Midwest utility, helped general counsel to evaluate and support legislation, and propose commission rules addressing rate riders for fuel and purchased power and the costs of complying with environmental regulations. Performed research on rate riders in other states; drafted proposed rules and tariff riders for client.
- **Rate Filings.** For a traditionally regulated Midwest utility, assisted counsel in preparing for a rate case. Helped draft testimonies regarding off-system sales margins and the cost of fuel.

Business Strategy

- **Evaluation of Cogeneration Venture.** For an unregulated division of a utility holding company, led the financial evaluation of a nascent venture to build and operate cogeneration facilities on customer sites. Estimated the market size and potential pricing, and assessed the client’s capabilities for delivering such services. Analyzed the target customer base in detail; performed technical cost analysis for building and operating cogeneration plants; analyzed retail/default rate structures against which new cogeneration would have to compete. Senior management followed our recommendations to shut down the venture.
- **Strategic Sourcing.** For a large, diversified manufacturer, coordinated a cross-business unit client team to reengineer processes for procuring electricity, natural gas, and demand-side management services. Worked with top executives to establish goals. Gathered data on energy usage patterns, costs, and contracts across hundreds of facilities. Interviewed energy managers, plant managers, and executives. Analyzed potential suppliers. Wrote RFPs and developed negotiating

SAMUEL A. NEWELL

strategy. Designed internal organizational structure (incorporating outsourced service providers) for managing energy procurement on an ongoing basis.

- **M&A Advisory.** For a European utility aiming to enter the U.S. markets and enhance their trading capability, evaluated acquisition targets. Assessed potential targets' capabilities and their value versus stock price. Reviewed experiences of acquirers in other M&A transactions. Advised client against an acquisition, just when the market was peaking (just prior to collapse).
- **Marketing Strategy.** For a large power equipment manufacturer, identified the most attractive target customers and joint-venture candidates for plant maintenance services. Evaluated the cost structure and equipment mix of candidates using FERC data and proprietary data. Estimated the potential value client could bring to each potential customer. Worked directly with company president to translate findings into a marketing strategy.
- **Distributed Generation (DG) Market Assessment.** For the unregulated division of an integrated utility, performed a market assessment of established and emerging DG technologies. Projected future market sizes across multiple market segments in the U.S. Concluded that DG presented little immediate threat to the client's traditional generation business, and that it presented few opportunities that the client was equipped to exploit.
- **Fuel Cells.** For a European fuel cell component manufacturer, acted as a technology and electricity advisor for a larger consulting team developing a market entry strategy in the U.S.

TESTIMONY and REGULATORY FILINGS

Before the Federal Energy Regulatory Commission Docket No. ER14-616-000, filed "Affidavit of Dr. Samuel A. Newell on behalf of ISO New England" and accompanying "2013 Offer Review Trigger Prices Study," December, 2013.

Before the American Arbitration Association, provided expert testimony (deposition, written report, and oral testimony at hearing) in a dispute involving the acquisition of a demand response company, July-November, 2013. (Non-public).

Before the Texas Public Utility Commission, presented "ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates" on behalf of The Electric Reliability Council of Texas (ERCOT) at a workshop in Project 40000 Commission Proceeding to Ensure Resource Adequacy in Texas, June 27, 2013. Subsequently filed additional comments, "Additional ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates," July 23, 2013.

Before the Federal Energy Regulatory Commission, filed "Affidavit of Dr. Samuel A. Newell on Behalf of the 'Competitive Markets Coalition' Group Of Generating Companies," supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model, Docket No. ER13-535-000, December 28, 2012.

SAMUEL A. NEWELL

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, supporting PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's Reliability Pricing Model, filed November 21, 2012.

Before the Texas Legislature Committee on State Affairs, presented oral testimony: "The Resource Adequacy Challenge in ERCOT" on behalf of The Electric Reliability Council of Texas, October 24, 2012.

Before the Texas Public Utility Commission, filed comments and presented "Resource Adequacy in ERCOT: 'Composite' Policy Options" and "Estimate of DR Potential in ERCOT" on behalf of ERCOT at a workshop in Project 40480 Commission Proceeding Regarding Policy Options on Resource Adequacy, October 25, 2012.

Before the Texas Public Utility Commission, filed comments and presented "Review of Resource Adequacy Proposals" on behalf of ERCOT at workshop in Project 40480 Commission Proceeding Regarding Policy Options on Resource Adequacy, September 6, 2012.

Before the Texas Public Utility Commission, filed comments and presented "Summary of Brattle's Study on 'ERCOT Investment Incentives and Resource Adequacy'" at workshop in Project 40000 Commission Proceeding to Ensure Resource Adequacy in Texas, July 27, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-___-000, Affidavit of Dr. Samuel A. Newell on Behalf of SIG Energy, LLLP, March 29, 2012, Confidential Exhibit A in Complaint of Sig Energy, LLLP, SIG Energy, LLLP v. California Independent System Operator Corporation, Docket No. EL 12-___-000, filed April 4, 2012 (Public version, confidential information removed).

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed January 13, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed December 1, 2011.

Before the Federal Energy Regulatory Commission, Docket Nos. ER11-4069 and ER11-4070, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine Companies, re: the public policy, congestion relief, and economic benefits of the RITELine Transmission Project, filed July 18, 2011.

Before the Federal Energy Regulatory Commission, Docket No. No. EL11-13-000, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies re: the public policy, reliability, congestion relief, and economic benefits of the Atlantic Wind Connection Project, filed December 20, 2010.

"Economic Evaluation of Alternative Demand Response Compensation Options," whitepaper filed by ISO-NE in its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000, October 13, 2010 (with K. Madjarov).

SAMUEL A. NEWELL

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference, October 5, 2010 (with K. Spees and P. Hanser).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Notice of Proposed Rulemaking regarding wholesale compensation of demand response, May 13, 2010 (with K. Spees and P. Hanser).

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2010 “Integrated Resource Plan for Connecticut” (see below), June 2010.

2010 “Integrated Resource Plan for Connecticut,” report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 4, 2010. Presented to the Connecticut Energy Advisory Board January 8, 2010.

“Dynamic Pricing: Potential Wholesale Market Benefits in New York State,” lead authors: Samuel Newell and Ahmad Faruqui at The Brattle Group, with contributors Michael Swider, Christopher Brown, Donna Pratt, Arvind Jaggi and Randy Bowers at the New York Independent System Operator, submitted as “Supplemental Comments of the NYISO Inc. on the Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure,” in State of New York Public Service Commission Case 09-M-0074, December 17, 2009.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2009 “Integrated Resource Plan for Connecticut” (see below), June 30, 2009.

2009 “Integrated Resource Plan for Connecticut,” report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 1, 2009.

“Informational Filing of the Internal Market Monitoring Unit’s Report Analyzing the Operations and Effectiveness of the Forward Capacity Market,” prepared by Dave LaPlante and Hung-po Chao of ISO-NE with Sam Newell, Metin Celebi, and Attila Hajos of The Brattle Group, filed with FERC on June 5, 2009 under Docket No. ER09-1282-000.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2008 “Integrated Resource Plan for Connecticut” and “Supplemental Reports” (see below), September 22-25, 2008.

“Integrated Resource Plan for Connecticut,” co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board; co-authored with M. Chupka, A. Faruqui, D. Murphy, and J. Wharton, January 2, 2008. Supplemental Report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Department of Utility Control; co-authored with M. Chupka, August 1, 2008.

SAMUEL A. NEWELL

“Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI’s Proposed Demand-Side Management Programs,” whitepaper by Samuel A. Newell and Ahmad Faruqui filed by Pepco Holdings, Inc. with the Public Utility Commissions of Delaware (Docket No. 07-28, 9/27/2007), Maryland (Case No. 9111, filed 12/21/07), New Jersey (BPU Docket No. EO07110881, filed 11/19/07), and Washington, DC (Formal Case No. 1056, filed 10/1/07). Presented orally to the Public Utility Commission of Delaware, September 5, 2007.

Before the Public Service Commission of Wisconsin, Docket 137-CE-149, “Planning Analysis of the Paddock-Rockdale Project,” report by American Transmission Company re: transmission cost-benefit analysis, April 5, 2007 (with J.P. Pfeifenberger and others).

Prepared Supplemental Testimony on Behalf of the Michigan Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-718-000 et al., re: Financial Impact of ComEd’s and AEP’s RTO Choices, December 21, 2004 (with J. P. Pfeifenberger).

Prepared Direct and Answering Testimony on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd’s and AEP’s RTO Choices on Michigan and Wisconsin, September 15, 2004 (with J.P. Pfeifenberger).

Declaration on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd’s and AEP’s RTO Choices on Michigan and Wisconsin, August 13, 2004 (with J.P. Pfeifenberger).

PUBLICATIONS

“Developing a Market Vision for MISO: Supporting a Reliable and Efficient Electricity System in the Midcontinent.” Foundational report prepared for Midcontinent Independent System Operator, Inc., January 27, 2014 (with K. Spees and N. Powers).

“Estimating the Economically Optimal Reserve Margin in ERCOT,” January 2014 (with J. Pfeifenberger, K. Spees and I. Karkatsouli).

“Resource Adequacy Requirements: Reliability and Economic Implications,” September 2013 (with J. Pfeifenberger, K. Spees).

“Capacity Markets: Lessons Learned from the First Decade,” Economics of Energy & Environmental Policy. Vol. 2, No. 2, Fall 2013 (with J. Pfeifenberger, K. Spees).

“ERCOT Investment Incentives and Resource Adequacy,” report prepared for the Electric Reliability Council of Texas, June 1, 2012 (with K. Spees, J. Pfeifenberger, R. Mudge, M. DeLucia, and R. Carlton).

“Trusting Capacity Markets: does the lack of long-term pricing undermine the financing of new power plants?” Public Utilities Fortnightly, December 2011 (with J. Pfeifenberger).

SAMUEL A. NEWELL

“Second Performance Assessment of PJM’s Reliability Pricing Model: Market Results 2007/08 through 2014/15,” report prepared for PJM Interconnection LLC, August 26, 2011 (with J. Pfeifenberger, K. Spees, and others).

“Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM,” report prepared for PJM Interconnection LLC, August 24, 2011 (with J. Pfeifenberger, K. Spees, and others).

“Fostering economic demand response in the Midwest ISO,” *Energy* 35 (2010) 1544–1552 (with A. Faruqui, A. Hajos, and R.M. Hledik).

“DR Distortion: Are Subsidies the Best Way to Achieve Smart Grid Goals?” *Public Utilities Fortnightly*, November 2010.

“Midwest ISO’s Resource Adequacy Construct: An Evaluation of Market Design Elements,” report prepared for MISO, January 2010 (with K. Spees and A. Hajos).

“Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design,” report prepared for MISO, January 2010 (with A. Hajos).

“Cost-Benefit Analysis of Replacing the NYISO’s Existing ICAP Market with a Forward Capacity Market,” whitepaper written for the NYISO and submitted to stakeholders, June 15, 2009 (with A. Bhattacharyya and K. Madjarov).

“Fostering Economic Demand Response in the Midwest ISO,” whitepaper written for MISO, December 30, 2008 (with R. Earle and A. Faruqui).

“Review of PJM’s Reliability Pricing Model (RPM),” report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, June 30, 2008 (with J. Pfeifenberger and others).

“Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches,” *Energy*, Vol. 1, 2008, The Brattle Group (with M. Chupka and D. Murphy).

“Enhancing Midwest ISO’s Market Rules to Advance Demand Response,” report written for MISO, March 12, 2008 (with R. Earle).

“The Power of Five Percent,” *The Electricity Journal*, October 2007 (with A. Faruqui, R. Hledik, and J. Pfeifenberger).

“Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI’s Proposed Demand-Side Management Programs,” whitepaper prepared for Pepco Holdings, Inc., September 21, 2007 (with A. Faruqui).

“Review of PJM’s Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets,” Report prepared for PJM Interconnection LLC, September 14, 2007 (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes and others).

SAMUEL A. NEWELL

“Valuing Demand-Response Benefits in Eastern PJM,” Public Utilities Fortnightly, March 2007 (with J. Pfeifenberger and F. Felder).

“Quantifying Demand Response Benefits in PJM,” study report prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative, January 29, 2007 (with F. Felder).

“Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models,” Energy, Vol. 2, 2006, The Brattle Group (with J. Pfeifenberger).

“Innovative Regulatory Models to Address Environmental Compliance Costs in the Utility Industry,” October 2005 Newsletter, American Bar Association, Section on Environment, Energy, and Resources; Vol. 3 No. 1 (with J. Pfeifenberger).

“Effect of Cross Sound Cable,” CERA Alert, October 24, 2003 (with H. Stauffer and G. Mukherjee).

PRESENTATIONS

“Capacity Markets: Lessons for New England from the First Decade,” presented to Restructuring Roundtable Capacity (and Energy) Market Design in New England, Boston, MA, February 28, 2014.

“The State of Things: Resource Adequacy in ERCOT” presented to INFOCAST – ERCOT Market Summit 2014 Panel Discussion, Austin, TX, February 24-26, 2014.

“Resource Adequacy in ERCOT” presented to FERC/NARUC Collaborative Winter Meeting in Washington, D.C., February 9, 2014.

“Electricity Supply Risks and Opportunities by Region” presentation and panel discussion at Power-Gen International 2013 Conference, Orlando, FL, November 13, 2013.

“Get Ready for Much Spikier Energy Prices—The Under-Appreciated Market Impacts of Displacing Generation with Demand Response,” presented to the Cadwalader Energy Investor Conference, New York, February 7, 2013 (with K. Spees).

“The Resource Adequacy Challenge in ERCOT,” presented to The Texas Public Policy Foundation’s 11th Annual Policy Orientation for legislators, January 11, 2013.

“Resource Adequacy in ERCOT: the Best Market Design Depends on Reliability Objectives,” presented to the Harvard Electricity Policy Group conference, Washington, D.C., December 6, 2012.

“Resource Adequacy in ERCOT,” presented to the Gulf Coast Power Association Fall Conference, Austin, TX, October 2, 2012.

“Texas Resource Adequacy,” presented to Power Across Texas, Austin, TX, September 21, 2012.

“Resource Adequacy and Demand Response in ERCOT,” presented to the Center for the Commercialization of Electric Technologies (CCET) Summer Board Meeting, Austin, TX, August 8, 2012.

SAMUEL A. NEWELL

“Summary of Brattle’s Study on ‘ERCOT Investment Incentives and Resource Adequacy,’” presented to the Texas Industrial Energy Consumers annual meeting, Austin, TX, July 18, 2012.

“Market-Based Approaches to Achieving Resource Adequacy,” presentation to Energy Bar Association Northeast Chapter Annual Meeting, Philadelphia, PA, June 6, 2012.

“Fundamentals of Western Markets: Panel Discussion,” WSPP’s Joint EC/OC Meeting, La Costa Resort, Carlsbad, CA, February 26, 2012 (with Jürgen Weiss).

“Integrated Resource Planning in Restructured States,” presentation at EUCI conference on “Supply and Demand-Side Resource Planning in ISO/RTO Market Regimes,” White Plains, NY, October 17, 2011.

“Demand Response Gets Market Prices: Now What?” NRRI teleseminar panelist, June 9, 2011.

Before the PJM Board of Directors and senior level representatives at PJM’s General Session, panel member serving as an expert in demand response on behalf of Pepco Holdings, Inc., December 22, 2007.

“Resource Adequacy in New England: Interactions with RPS and RGGI,” Energy in the Northeast Law Seminars International Conference, Boston, MA, October 18, 2007.

“Corporate Responsibility to Stakeholders and Criteria for Assessing Resource Options in Light of Environmental Concerns,” Bonbright Electric & Natural Gas 2007 Conference, Atlanta, GA, October 3, 2007.

“Evaluating the Economic Benefits of Transmission Investments,” EUCI’s Cost-Effective Transmission Technology Conference, Nashville, May 3, 2007 (with J. Pfeifenberger, presenter).

“Quantifying Demand Response Benefits in PJM,” PowerPoint presentation to the Mid-Atlantic Distributed Resources Initiative (MADRI) Executive Committee on January 13, 2007, to the MADRI Working Group on February 6, 2007, as Webinar to the U.S. Demand Response Coordinating Council, and to the Pennsylvania Public Utility Commission staff April 27, 2007.

“Who Will Pay for Transmission,” CERA Expert Interview, Cambridge, MA, January 15, 2004.

“Reliability Lessons from the Blackout; Transmission Needs in the Southwest,” presented at the Transmission Management, Reliability, and Siting Workshop sponsored by Salt River Project and the University of Arizona, Phoenix, AZ, December 4, 2003.

“Application of the ‘Beneficiary Pays’ Concept,” presented at the CERA Executive Retreat, Montreal, Canada, September 17, 2003.

March 31, 2014

KATHLEEN SPEES

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Dr. Kathleen Spees is a Senior Associate at *The Brattle Group* with expertise wholesale electric energy, capacity, and ancillary service market design and price forecasting. Dr. Spees has worked with market operators in PJM, MISO, Alberta, ERCOT, ISO-NE, and Italy to independently assess and improve their market designs for resource adequacy, increase efficiency of energy and capacity market seams, investigate market manipulation of virtual trading and FTR markets, evaluate system impacts from environmental coal retirements, evaluate the supply chain impacts of major simultaneous environmental retrofits, conduct engineering studies on the cost of building new generation facilities, develop capacity market demand curves, and refine wind integration rules for both interconnection and dispatch. She has worked with market participants in these and other U.S. RTOs to conduct asset valuation exercises including capacity, energy, and ancillary service price forecasts, economic dispatch modeling of power plants, and valuation of power purchase agreement terms. For various clients, Dr. Spees has developed structural market models or plant-specific valuation models to support contract negotiation, power plant transactions, investment decisions, and market bidding strategy. Her project work has included efforts to estimate demand response penetration impacts, structurally analyze client concerns or questions about virtual trading, FTR, or ancillary service markets, impacts of environmental regulations on coal retirements, tariff mechanisms for accommodating merchant transmission upgrades, renewables integration approaches, and market treatment of storage assets.

Dr. Spees earned her PhD in Engineering and Public Policy within the Carnegie Mellon Electricity Industry Center and her MS in Electrical and Computer Engineering from Carnegie Mellon University. She earned her BS in Physics and Mechanical Engineering from Iowa State University.

Publications posted: <http://www.brattle.com/experts/kathleen-spees>

REPRESENTATIVE EXPERIENCE

- **MISO Market Development Vision.** For the Midcontinent Independent System Operator (MISO), worked with MISO staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2-5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities for improving MISO's electricity market; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- **ERCOT Economically Optimal Reserve Margin.** For the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT), co-authored a report estimating the economically-optimal reserve margin. Compared to various reliability-based reserve margins, and evaluated the cost and uncertainty of energy-only and a potential capacity market in ERCOT. Conducted the study in collaboration with Astrape Consulting to

KATHLEEN SPEES

construct a series of economic and reliability modeling simulations that account for uncertain weather patterns, generation and transmission outages, and multi-year load forecasting errors. The simulations also incorporate detailed representation of the Texas power market, including intermittent wind and solar generation, operating reserves, different types of demand response, the full range of emergency procedures (such as operating reserve deletion), scarcity pricing provisions, and load-shed events.

- **Economic Implications of Resource Adequacy Requirements.** For the Federal Energy Regulatory Commission (FERC), reviewed economic and reliability implications of resource adequacy requirements based on traditional reliability criteria as well as alternative standards based on economic criteria. Evaluated total system costs, customer costs, supplier net revenues, and demand response implications under a range of reserve margins as well as under varying energy-only and capacity market designs.
- **MISO Wind Curtailment.** For MISO, evaluated the efficiency and equity implications of wind curtailment prioritization mechanisms and options for addressing stakeholder concerns, including interconnection agreement types, energy and capacity injection rights, ARR/FTR allocation mechanisms, energy market offers, and market participant hedging needs.
- **California Resource Adequacy Construct Review.** Sponsored by Calpine, evaluated and recommended efficiency improvements to California's resource adequacy construct mechanisms including long-term procurement, short-term local resource adequacy, and CAISO backstop mechanisms.
- **ERCOT Resource Adequacy Review.** For ERCOT, Evaluated wholesale market design in the context of its ability to attract sufficient investment for resource adequacy, when and where needed, including an evaluation of the implications of large simultaneous environmental retirements.
- **MISO Coal Retrofit Supply Chain Analysis.** For MISO, Examined the supply chain and outage scheduling implications of large simultaneous environmental retirements.
- **Italian Capacity Market Design.** For Italy's transmission system operator Terna, supported development of a locational capacity market design and locational capacity demand curves based on simulation modeling on the value of capacity to customers.
- **Survey of Energy Market Seams.** For the Alberta Electric System Operator (AESO), assessed the implications of energy market seams inefficiencies between power markets in Canada, the U.S., and Europe for the Alberta Electric System Operator. Evaluation of options for improving seams based on other markets' experiences with inter-regional transmission upgrades, energy market scheduling and dispatch, transmission rights models, and resource adequacy.
- **MISO Resource Adequacy Construct.** For MISO, conducted a review of the Midwest ISO's resource adequacy construct. Subsequent and ongoing assistance to MISO in enhancing the market design for resource adequacy related to market redesign, capacity market seams, and accommodation of both regulated and restructured states. Provided background

KATHLEEN SPEES

presentations to stakeholders on the capacity market design provisions of NYISO, PJM, CAISO, and ISO-NE.

- **PJM Review of Resource Adequacy and Capacity Market Design.** For PJM Interconnection, conducted a review of PJM's Reliability Pricing Model (RPM) on behalf of the market operator. Analyzed market functioning for resource adequacy including uncertainty and volatility of prices, impacts of administrative parameters and regulatory uncertainties, locational mechanisms, demand curve shape, incremental auction procedures, and other market mechanisms. Related testimony submitted before the Maryland Public Service Commission.
- **Cost of New Entry Study to Determine PJM Auction Parameters.** For PJM Interconnection, partnered with engineering, procurement, and construction firm to develop bottom-up cost estimates for building new gas combined cycles and combustion turbines. Affidavit before the Federal Energy Regulatory Commission and participation in ongoing settlement discussions on the same.
- **Alberta Energy-Only Market Review for Long-Term Sustainability: 2011 and 2013 Update.** For AESO, conducted a review of the ability of the energy-only market to attract and retain sufficient levels of capacity for long-term resource adequacy. Evaluation of the outlook for revenue sufficiency under forecasted carbon, gas, and electric prices, potential impact of environmentally-driven retirements, potential federal coal retirement mandate, and provincial energy policies.
- **Review of International Energy-Only, Capacity Market and Capacity Payment Mechanisms.** For PJM Interconnection, conducted a review of energy-only markets, capacity payment systems, and capacity markets on behalf of PJM market operator. Reviewed reliability, volatility, and overall investment outcomes related to details of market designs in bilateral, centralized, and forward commitment markets.
- **Russian Capacity and Natural Gas Market Liberalization.** On behalf of a market participant, conducted an assessment of market design, regulatory uncertainty, and liberalization success. Focus was on the efficiency of market design rules in the newly introduced system of capacity contracts combined with capacity payments, as well as on the impacts of gas price liberalization delays.
- **Tariff Design for Merchant Transmission Upgrades.** For a transmission developer, evaluated tariff design options for capturing market value of wind and transmission for a market participant proposing a large HVDC upgrade to enable wind developments.
- **PJM Capacity Market Price and Supply Adequacy Forecasting.** For multiple clients, capacity market price analysis, forecasting, and simulations for a number of clients to support investment decisions and bidding strategy. Equilibrium analysis based on projected energy prices and supply-demand fundamentals. Uncertainty analysis surrounding impacts from likely retirements, new builds, state supply contracts, transmission upgrades, demand response penetration potential, and seasonal demand response products.

KATHLEEN SPEES

- **ISO-NE Capacity Market Regulatory Analysis and Price Forecasting.** For multiple clients, capacity price forecasting assuming perfect-foresight retirement and new entry decisions by suppliers, based on going-forward economics including price floor expiration, required environmental upgrades, options to mothball, demand response supply curve, and energy margins.
- **Generation Asset Valuations in PJM, ISO-NE, MISO, and ERCOT.** For multiple clients, top-line operating cost and *revenues* estimation for clients in a number of different markets, to support investment decision-making regarding asset purchases, sales, or contract negotiations. Evaluations for a number of different asset classes including gas combined cycles, gas- and oil-fired combustion turbines, gas cogeneration, wind, and waste-to-energy facilities. Forecasting locational fuel, emissions, capacity, energy, and ancillary services prices. Detailed plant dispatch modeling against forecasted hourly energy and ancillary price profiles including incorporation of dispatch constraints such as steam obligations, startup costs, maintenance contract provisions, and power purchase agreement terms. Producing back-casts for dispatch validation and forecasts for future operating margins estimates.
- **Wind and Storage.** For a developer of potential storage assets, simulation analysis modeling combined effects of gas dispatch, wind variability, load variability, and minimum generation conditions to determine the value of electric storage under various levels of wind penetration. Conducted portfolio analysis to determine the optimal level of storage on a systems level to minimize cost as a function of wind penetration levels.
- **Impact of Carbon Prices on Coal Generator Retirement.** For a PJM market participant, conducted a zone-level analysis of PJM market prices and used unit-level data to conduct a virtual dispatch of coal units under a series of long-term capacity, fuel, and carbon price scenarios. Modeled retirement decisions of plants by PJM zone and the effect of the carbon price on the location and aggregate size of these retirement decisions.
- **Southern Company Independent Auction Monitor.** Sponsored by Southern Company, developed auction monitoring capability and protocol development for daily and annual audits of internal company processes and data inputs related to load forecasting, purchases and sales, and outage declarations. Analysis of company data to develop monitoring protocols and automated tools. Coordinated implementation of data collection and aggregation system required for market oversight and for detailed internal company data audits.
- **FTR and Virtual Bidding Market Manipulation Litigation for PJM.** For PJM Interconnection, analyzed financial transmission rights, energy market, and virtual trading data for expert testimony regarding market manipulation behavior.

SELECTED PUBLICATIONS AND REPORTS

Newell, Samuel A., Johannes P. Pfeifenberger, and Kathleen Spees. *Estimating the Economically Optimal Reserve Margin in ERCOT*. Prepared for the Public Utility Commission of Texas and the Electric Reliability Council of Texas. January 31, 2014.

KATHLEEN SPEES

- Newell, Samuel A., and Kathleen Spees. *Developing a Market Vision for MISO: Supporting a Reliable and Efficient Electricity System in the Midcontinent*. January 27, 2014.
- Spees, Kathleen, Samuel A. Newell, and Johannes Pfeifenberger. "Capacity Markets: Lessons Learned from the First Decade," published in *Economics of Energy & Environmental Policy*. Vol. 2, No. 2. September 2013.
- Pfeifenberger, Johannes, Kathleen Spees, Kevin Carden, and Nick Wintermantel. *Resource Adequacy Requirements: Reliability and Economic Implications*. Prepared for the Federal Energy Regulatory Commission. September 2013.
- Pfeifenberger, Johannes P., Kathleen Spees, and Michael DeLucia. Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market: 2013 Update, prepared for the Alberta Electric System Operator. March 2013.
- Spees, Kathleen and Hannes Pfeifenberger. "PJM Reliability Pricing Model: 2016/17 Planning Period Parameters Update," prepared for Barclays North American Utilities Investor Call. February 4, 2013.
- Pfeifenberger, Johannes P., Kathleen Spees, and Samuel A. Newell. Resource Adequacy in California: Options for Improving Efficiency and Effectiveness," prepared for Calpine. October 2012.
- Newell, Samuel A., Kathleen Spees, Johannes P. Pfeifenberger, Robert S. Mudge, Michael DeLucia, and Robert Carlton. ERCOT Investment Incentives and Resource Adequacy. Prepared for the Electric Reliability Council of Texas. June 1, 2012.
- Celebi, Metin, Kathleen Spees, Quincy Liao, and Steve Eisenhart. Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS.
- Pfeifenberger, Johannes, Kathleen Spees, Attila Hajos, Delphine Hou, and Dan Harris. Alberta's Intertie Challenges: A Survey of Market Design Options for Seams Between Power Markets. Forthcoming.
- Pfeifenberger, Johannes P., Samuel A. Newell, Kathleen Spees, Attila Hajos, and Kamen Madjarov. Second Performance Assessment of PJM's Reliability Pricing Model. Prepared for PJM Interconnection. August 26, 2011.
- Spees, Kathleen, Samuel A. Newell, Johannes P. Pfeifenberger, Robert Carlton, and Bin Zhou. Cost of New Entry Estimates for Combustion Turbine and Combined-Cycle Plants in PJM. Prepared for PJM Interconnection. August 24, 2011.
- Pfeifenberger, Johannes P., and Kathleen Spees. Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market. Prepared for the Alberta Electric System Operator. April 2011.
- Newell, Samuel A., Kathleen Spees, and Attila Hajos. *Midwest ISO's Resource Adequacy Construct: an Evaluation of Market Design Elements*. Prepared for the Midwest Independent System Operator.

KATHLEEN SPEES

January 19, 2010.

Pfeifenberger, Johannes P., Kathleen Spees, and Adam C. Schumacher. *A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs*. Prepared for PJM Interconnection. September 2009.

Spees, Kathleen. "Meeting Electric Peak on the Demand Side: Wholesale and Retail Market Impacts of Real-Time Pricing and Peak Load Management Policy," PhD Thesis, Carnegie Mellon University.

Spees, Kathleen with Lester Lave, Jay Apt, and M. Granger Morgan. "Policy Brief on the Smart Metering, Peak Load Reduction, and Efficiency Provisions of House Bills 2200 and 2201," June 13, 2008.

Technology: Enabling the Transformation of Power Distribution. Prepared by the Center for the Study of Science, Technology, & Policy (Contributions from Kathleen Spees), and Infosys for the Ministry of Power of India.

Spees, Kathleen. "Real-Time Pricing as an Effective Substitute for Electric Generation Capacity: How Innovative Retail Electric Services Can Benefit the Grid," *Network Industries Quarterly*. Spring 2007.

Spees, Kathleen, and Lester Lave. "Do RTOs Promote Renewables? A Study of State-Level Data over Time." Working Paper CEIC-07-14.

Spees, Kathleen, and Lester Lave. "Impacts of Responsive Load in PJM: Load Shifting and Real Time Pricing." 2007. *The Energy Journal*. Vol. 29, No. 2. 2008.

Spees, Kathleen, and Lester Lave. "Demand Response and Electricity Market Efficiency." *The Electricity Journal*. Volume 20, Issue 3, April 2007.

Apt, Jay, Seth Blumsack, and Lester B. Lave with contributions from Lee Gresham, Adam Newcomer, Kathleen Spees, and Rahul Walawalkar. *Competitive Energy Options for Pennsylvania*. Carnegie Mellon Electricity Industry Center. January 2007.

Fowler, Kimberly, Amy Solana, and Kathleen Spees. *Building Cost and Performance Metrics: Data Collection Protocol, Revision 1.1*. Prepared by Pacific Northwest National Laboratory for the Federal Energy Management Program, September 2005.

SELECTED TESTIMONY

Newell, Samuel A. and Kathleen Spees. "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC, Regarding the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model." Before the Federal Energy Regulatory Commission. Docket No. ER12-13-000. January 13, 2012.

Newell, Samuel, Kathleen Spees, and Philip Q. Hanser. Supplemental Comments, Re: Notice of Proposed Rulemaking regarding Demand Response Compensation in Organized Wholesale Energy

KATHLEEN SPEES

Markets. Before the Federal Energy Regulatory Commission. October 4, 2010. Docket Nos. RM10-17-000 and EL09-68-00.

Pfeifenberger, Johannes P. and Kathleen Spees. Comments In the Matter of the Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results. Before the State of Maryland Public Service Commission. Administrative Docket PC22. Filed October 1, 2010.

Newell, Samuel, Kathleen Spees, and Philip Q. Hanser. Comments, Re: Notice of Proposed Rulemaking regarding Demand Response Compensation in Organized Wholesale Energy Markets. Before the Federal Energy Regulatory Commission. May 13, 2010. Docket Nos. RM10-17-000 and EL09-68-00.

SELECTED PRESENTATIONS

Pfeifenberger, Johannes P., Samuel A. Newell, and Kathleen Spees. “Energy and Capacity Markets: Tradeoffs in Reliability, Costs, and Risks,” presented at the Harvard Electricity Policy Group Seventy-Fourth Plenary Session. February 27, 2014.

Spees, Kathleen, Johannes P. Pfeifenberger, and Samuel A. Newell. “ERCOT’s Optimal Reserve Margin,” presented to UBS Investment Research investor conference call. February 19, 2014.

Spees, Kathleen. “Capacity Markets: Lessons Learned from the First Decade,” presented to EUCI 10th Annual Capacity Markets Conference. November 7, 2013.

Pfeifenberger, Johannes P, and Kathleen Spees. “Characteristics of Successful Capacity Markets,” presented at the APEx Conference 2013, New York, NY. October 31, 2013.

Spees, Kathleen and Johannes Pfeifenberger. “Outlook on Fundamentals in PJM’s Energy and Capacity Markets,” presented at the 12th Annual Power and Utility Conference, Hosted by Goldman Sachs. August 8, 2013.

Newell, Samuel A., and Kathleen Spees. “Get Ready for Much Spikier Energy Prices: The Under-Appreciated Market Impacts of Displacing Generation with Demand Response,” presented at the Cadwalader Energy Investor Conference. February 7, 2013.

Spees, Kathleen and Johannes P. Pfeifenberger. “PJM Reliability Pricing Model: 2016/17 Planning Period Parameters Update,” presented to Barclays North American Utilities Investor Call. February 4, 2013.

Spees, Kathleen and Johannes P. Pfeifenberger. “Seams Inefficiencies: Problems and Solutions at Energy Market Borders,” presented at the EUCI Canadian Transmission Summit. July 17, 2012.

Spees, Kathleen. “New U.S. Emission Regulations: Electric Industry Impacts,” presented at the U.S. Energy 24th Annual Energy Conference. May 11, 2012.

Spees, Kathleen. “Market Design from a Practitioner’s Viewpoint: Wholesale Electric Market Design for Resource Adequacy,” presented at Lawrence University Economics Colloquium. April 23, 2012.

KATHLEEN SPEES

Spees, Kathleen. “Options for Extending Forward certainty in Capacity Markets.” Presented at the EUCI Conference on Capacity Markets: Achieving Market Price Equilibrium. November 9, 2011.

Spees, Kathleen, and Pfeifenberger, Johannes P. “Resource Adequacy: Current Issues in North American Power Markets.” Presented at the Alberta Power Summit. November 19, 2011.

Spees, Kathleen and Samuel Newell. “Capacity Market Designs: Focus on CAISO, NYISO, PJM, and ISO-NE,” Presented to the Midwest ISO Supply Adequacy Working Group. July 19, 2010.

Pfeifenberger, Johannes P., and Kathleen Spees. “Best Practices in Resource Adequacy,” presented at the PJM Long Term Capacity Issues Symposium. January 27, 2010.

Chang, Judy, Kathleen Spees, and Jurgen Weiss. “Using Storage to Capture Renewables: Does Size Matter?” working paper presented at the 15th Annual POWER Research Conference. University of California Energy Institute’s Center for the Study of Energy Markets. March 18, 2010.

EDUCATION

University of Tennessee, Master of Business Administration, 1984
Massachusetts Institute of Technology, M.S. Civil Engineering, 1974
Massachusetts Institute of Technology, B. S. Civil Engineering, 1973

REGISTRATIONS

Professional Engineer - Tennessee

EXPERTISE

Utility Planning
Technology Evaluation
Market Analysis
Asset Valuation

Condition Assessment
Due Diligence
Risk Analysis
Expert Witness

RESPONSIBILITIES

Mr. Ungate is accountable for Sargent & Lundy offerings in the Utility Planning business segment. He develops and evaluates integrated resource plans and associated analyses to identify and evaluate the optimum power supply options. He reviews and evaluates power supply planning and procurement options such as generation options (potential greenfield or plant expansion options), the viability of siting and permitting new gas, wind, solar, biomass, coal, nuclear or other alternatives, the prospects for purchase of existing assets, and the potential for partnering with other load serving entities or power generators. He also assesses the state of transmission planning and upgrade programs, and the fuel market and transportation capacities. He assures consistency with the Client's long-term plans and objectives and Client-specific economic factors.

Mr. Ungate supports ISOs and utility clients with cost and performance estimates of new entrant technologies. He develops analyses utilized in the assessment of power generation technologies, project development, asset transactions, operational reviews, and facility modifications and refurbishment projects. He evaluates and develops plans to optimize the utilization of renewable energy resources with thermal generating units and storage technologies. He also performs due diligence reviews of new technology development, new projects, modifications and refurbishment of existing facilities, asset transactions, and condition and operational assessments.

EXPERIENCE

Mr. Ungate has over 35 years of experience in engineering and planning for electric utilities. His most recent utility planning assignments since joining Sargent & Lundy in 2006 include:

- **Long Island Power Authority, 2014**
 - Sargent & Lundy is assisting the Long Island Power Authority (LIPA) in the evaluation and selection of bids for new generation, energy storage and demand response bids

submitted to LIPA under terms of a November 2013 Request for Proposals (RFP). The assignment includes development of an evaluation model; handling of bid administration; screening for responsiveness of bids to RFP requirements; a quantitative and qualitative assessment of responsive proposals to identify a short list; detailed quantitative and qualitative technical, economic and financial analyses of short listed bids; and formulation of recommendations for LIPA decision making.

- **PJM Interconnection, 2013-14**
 - Sargent & Lundy is supporting The Brattle Group’s review of PJM’s Variable Resource Requirement (VRR) curve, which is an administratively determined representation of a demand curve for capacity used in the PJM Reliability Pricing Model auction. S&L’s role is to estimate (a) total gross overnight capital costs including most owner’s costs, all owner-furnished equipment, and all engineering procurement and construction (EPC) balance of plant costs; (b) a capital drawdown schedule to be used in calculating interest during construction in the capital budgeting model; (c) first-year fixed operations and maintenance (FOM) costs including staffing, asset management, and other annual fixed costs; and (d) performance data relevant for calculating cost of new entry and net energy revenues including plant heat rate and summer capacity rating.
- **ISO New England, 2013-14**
 - Sargent & Lundy is supporting The Brattle Group’s development of the ISO New England’s capacity demand curve proposal. S&L is supporting the selection of a reference technology, identifying key assumptions required to estimate the cost and performance of the reference technology in New England, and develop cost and performance estimates for the reference technology in local regions of ISO New England as necessary.
- **NIPSCO, 2013**
 - Sargent & Lundy developed cost and performance estimates for gas, coal, nuclear, renewable, storage and distributed generation technology alternatives to be evaluated in NIPSCO’s Integrated Resource Plan (IRP) for 2014. Sargent & Lundy prepared a Technical Assessment Report that outlines the methodology and results. The report will be included in NIPSCO’s submittal of its IRP to the Indiana Public Service Commission.
- **ACES, 2013**
 - Sargent & Lundy developed cost and performance information for new build natural gas fired generation options for use by ACES in supporting development of mid- to long-term power supply strategies with its members and customers. In addition to developing assumptions and estimating the cost and performance of each option for an assumed Midwest U.S. location, S&L will develop an approach for ACES’s use in translating the cost estimates to other sites where ACES’ members and customers are located.
- **New York Independent System Operator, 2007- present**
 - Estimated the cost of new entrant peaking units used in the updating of demand curves for the NYISO capacity market in 2007, 2010 and 2013. Estimated going

forward costs of existing generation used in determining need for market power mitigation. Estimated cost of new entry for proposed projects used to determine need for buyer side mitigation. Assisted in development of technical assessment process supporting a determination of whether a generator could transfer interconnection service rights when proposing to repower a generating unit.

- **ISO New England, 2013**

- Sargent & Lundy partnered with The Brattle Group to estimate the Offer Review Trigger Prices used by ISO New England as part of its market mitigation process. S&L's scope was to estimate capital and O&M costs for several technologies in the New England states, including natural gas-fired simple and combined cycle plants, biomass, onshore and offshore wind and solar photovoltaic technologies.

- **Confidential Client**

- Sargent & Lundy supported The Brattle Group with an evaluation of the feasibility of supply options proposed in response to a Request for Proposals. The feasibility analysis identified supply options that could be placed in service for a stringent near term commercial operation date.

- **Ontario Power Authority, 2013**

- Sargent & Lundy partnered with NERA to develop a cost and performance estimate for a simple cycle, natural gas fired frame combustion turbine unit in the Southwest Greater Toronto Area (GTA) in the province of Ontario, Canada.

- **Maui Electric Company, 2012-13**

- Conducted a Generation Asset Assessment Study to review the condition of Maui Electric's generating facilities and the impact of the expected changes in usage resulting from increasing amounts of intermittent renewable resources. Each unit's remaining useful life and performance was assessed given the expected operational demands. Operational and maintenance adjustments were proposed to maximize the performance and useful life of the units.

- **GenOn Energy, 2012**

- Estimated the cost of new entrant peaking and combined cycle units in two PJM zones to support GenOn's comments on PJM's CONE pricing proposal. Made presentation to and answered questions from participants in FERC Settlement Conference held to develop an agreement on the value of CONE.

- **Grand Haven Board of Light and Power, Zeeland Board of Public Works, 2011-12**

- Prepared individual Integrated Resource Plans for two Michigan municipal utilities as part of a single study. Parts of the study related to their location in Ottawa County Michigan were common to both utilities. Potential resource options included existing and new non-renewable generation facilities, renewable energy resources, energy conservation and demand reduction programs, and long-term power purchase agreements or shared ownership options in large economies-of-scale facilities. Risk analysis was performed to evaluate how portfolio options performed under varying fuel and market prices, and environmental regulatory scenarios.

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- **NV Energy, 2011-12**
 - Developed simple and combined cycle natural gas fired capacity expansion options at six brownfield sites in Clark County, NV, to support development of the Integrated Resource Plan. Factors considered in the development of options included emissions, water availability, transmission constraints, natural gas availability, and the shape and amount of space available at the site.
 - **SaskPower, 2011-12**
 - Supervised a review of corporate resource planning processes. Processes and work products were compared to state-of-the-art utility industry examples and gaps identified. Recommendations for process improvements were prepared.
 - **Confidential Client, 2011**
 - Led a due diligence study of a potential investment in temporary power services to countries with developing economies based on diesel engine technology.
 - **Seven States Power Corporation, 2011**
 - Reviewed the performance history, environmental and regulatory requirements, contractual agreements, and operations and maintenance activities and plans for two natural gas fired combined cycle plants in support of a potential acquisition.
 - **Confidential Client, 2011**
 - Reviewed the operating history, environmental and regulatory requirements, and contractual agreements, and identified potential operational limitations, plant upgrades, and expected operating life for four coal or natural gas fired cogeneration plants in support of a potential transaction.
 - **Confidential Client, 2010-11**
 - Led the preparation of a business plan for a client considering whether to develop a fleet of generating plants based on small modular nuclear reactor technology.
 - **Tennessee Valley Authority, 2010**
 - Supported preparation of the Need for Power and Alternatives sections of the Integrated Resource Plan. Developed Need for Power and Alternatives sections for Environmental Impact Statements for Sequoyah Nuclear Plant Relicensing and Bellefonte Nuclear Plant Unit 1 that were prepared concurrently.
 - **South Mississippi Electric Power Association, 2009-10**
 - Reviewed renewable energy alternatives for this G&T cooperative in anticipation of future Renewable Portfolio Standard requirements. Directed the evaluation of responses to an RFP for renewable energy and capacity.
 - **New England Power Generators Association, 2010**
 - Estimated the cost of new entrant peaking units in New England for a NEPGA proposal to revise the basis for capacity payments in ISO-NE.
 - **PSEG, 2009-10**
 - Developed the need for power and energy alternatives analyses to satisfy the NUREG 1555 requirements for Environmental Reports associated with an Early Site

Permit Application for a new nuclear plant project. Responded to NRC questions on need for power and alternatives at the environmental site audit. Prepared responses to Requests for Additional Information.

Prior to joining Sargent & Lundy, Mr. Ungate had over 30 years of experience at the Tennessee Valley Authority in a variety of engineering and planning assignments. Examples of assignments include the following:

- Directed supply planning for 30,000 MWs of nuclear, coal, gas, renewable, and hydro generation, and determined peak season power purchase requirements. Directed the preparation of power supply plans, and the valuation of capacity additions, major projects, product offerings, and bulk power transactions.
- Led environmental controls optimization study to determine least cost approach to meeting CAIR/CAMR requirements for TVA's 15,000 MW coal generation portfolio. Alternatives included mothballing of units; increased allowance purchases; modified capital improvement programs; re-powering; and replacement with capacity and energy purchases from gas-fired units.
- Directed business planning for portfolio of 109 conventional hydropower units at 29 sites and four pumped storage units. Portfolio supplies 10-15% of company sales with 5000 MWs of capacity. Developed a five year business plan to increase resources to facilitate the transition to a process management maintenance strategy, and to integrate plant modernization and automation projects to change technology and workflow at the plants.
- Directed the first reassessment of the operating policies of Tennessee Valley Authority reservoirs since the system was designed in the 1930's. Directed the development of an operating scheme that preserved hydropower value while improving summer lake levels for recreation and increasing minimum flows for water quality.

TESTIMONY AND REGULATORY FILINGS

Before the Federal Energy Regulatory Commission, Docket No. ER14-500-000, Affidavit of Christopher D. Ungate on Behalf of New York Independent System Operator, re: answer to protests that challenged its November 29, 2013, filing of Proposed Tariff Revisions to Implement Revised ICAP Demand Curves and a New ICAP Demand Curve for Capability Years 2014/2015, 2015/2016 and 2016/2017, filed January 7, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-____-000, Affidavit of Christopher D. Ungate on Behalf of ISO New England, re: Revisions to Forward Capacity Market Offer Review Trigger Price Provisions, filed December 11, 2013.

Before the Federal Energy Regulatory Commission, FERC Docket No. ER12-513-000, presented oral testimony on behalf of GenOn Energy, Inc., re: comments and limited protest of PJM Interconnection, LLC's December 1, 2011 filing of modifications to the Reliability Pricing Model incorporated in Attachment DD of PJM's Open Access Transmission Tariff, April 18-19, 2012; May 21, 2012; and June 20, 2012

Before the Federal Energy Regulatory Commission, Docket No. ER11-2224-000, Affidavit of Christopher D. Ungate on Behalf of New York Independent System Operator, re: compliance with the Commission's January 28, 2011 Order on the NYISO's filing proposing updated Installed Capacity Demand Curves for Capability years 2011/2012, 2012/2013, and 2013/2014, filed March 29, 2011.

Before the Federal Energy Regulatory Commission, Docket No. ER11-2224-000, Affidavit of Christopher D. Ungate on Behalf of New York Independent System Operator, re: answer to protests that challenged its November 30, 2010, filing proposing revised ICAP Demand Curves, filed January 4, 2011.

Before the Federal Energy Regulatory Commission, Docket Nos. ER10-787-____, ER10-50-____ and ER10-57-____, Affidavit of Christopher D. Ungate on Behalf of New England Power Generators Association, Inc., re: Responses to Issues Addressed in the Commission's Hearing Order on Forward Capacity Market Revisions and Related Complaints, filed July 1, 2010.

Before the Federal Energy Regulatory Commission, Docket No. ER08-____-000, Affidavit of Christopher D. Ungate on Behalf of New York Independent System Operator, re: support for Tariff Revisions to Implement Revised ICAP Demand Curves for Capability Years 2008/2009, 2009/2010 and 2010/2011, filed November 29, 2007.

Before the Federal Energy Regulatory Commission, Docket No. EL07-39-000, Affidavit of Christopher D. Ungate on Behalf of New York Independent System Operator, re: revised market rules for NYC Installed Capacity to address buyer and seller market power concerns, filed October 2, 2007.

**MARCH 21, 2014 PARTICIPANTS COMMITTEE MEETING
VOTE TAKEN TO SUPPORT
FCM DEMAND CURVE PROPOSAL**

TOTAL

Participant Name	VOTE
GENERATION	5.72
TRANSMISSION	17.17
SUPPLIER	14.44
ALTERNATIVE RESOURCES	14.17
PUBLICLY OWNED ENTITY	0.86
END USER	17.17
% IN FAVOR	69.53

GENERATION SECTOR

Participant Name	VOTE
Dominion Energy Marketing, Inc.	A
Entergy Nuclear Power Marketing LLC	O
EquiPower Resources Management LLC	F
Essential Power, LLC	F
GDF SUEZ Energy Marketing NA, Inc.	O
Generation Group Member	F
Millennium Power Partners	O
NextEra Energy Resources, LLC	O
NRG Power Marketing, LLC	O
TransCanada Power Marketing Ltd.	O
IN FAVOR (F)	3
OPPOSED (O)	6
TOTAL VOTES	9
ABSTENTIONS (A)	1

TRANSMISSION SECTOR

Participant Name	VOTE
Central Maine Power Company	F
Emera Maine	F
New England Power Company	A
NU / NSTAR	F
The United Illuminating Company	F
Vermont Electric Power Company	F
IN FAVOR (F)	5
OPPOSED (O)	0
TOTAL VOTES	5
ABSTENTIONS (A)	1

SUPPLIER SECTOR

Participant Name	VOTE
BP Energy Company	A
Brookfield Energy Marketing Inc. / CSC	S
Brookfield Energy Marketing Inc.	A
Cross Sound Cable Company	F
Calpine Energy Services	A
Consolidated Edison Energy, Inc.	F
Dynegy Marketing and Trade, LLC	A
Energy America, LLC	A
Exelon Generation Company	O
Galt Power, Inc.	A
Granite Ridge Energy LLC	F
H.Q. Energy Services (U.S.) Inc.	F
Hess Corporation	A
Integrus Energy Services, Inc.	A
Kimberly-Clark Corporation	A
LIPA	F
Marble River, LLC	F
PPL EnergyPlus, LLC	A
PSEG Energy Resources & Trade LLC	A
IN FAVOR (F)	5.3
OPPOSED (O)	1.0
TOTAL VOTES	6.3
ABSTENTIONS (A)	10.7

ALTERNATIVE RESOURCES SECTOR

Participant Name	VOTE
Renewable Generation Sub-Sector	
First Wind Energy Marketing	F
Small RG Group Member	F
Distributed Generation Sub-Sector	
Conservation Services Group	F
Small DG Group Member	F
Load Response Sub-Sector	
EnerNOC, Inc.	A
Enerwise Global Technologies Inc.	A
LR Provisional Group Member	F
Small LR Group Member	F
Vermont Energy Investment Corp.	F
IN FAVOR (F)	7
OPPOSED (O)	0
TOTAL VOTES	7
ABSTENTIONS (A)	2

**MARCH 21, 2014 PARTICIPANTS COMMITTEE MEETING
VOTE TAKEN TO SUPPORT
FCM DEMAND CURVE PROPOSAL**

PUBLICLY OWNED ENTITY SECTOR

Participant Name	VOTE
Ashburnham Municipal Light Plant	O
Boylston Municipal Light Department	O
Braintree Electric Light Department	F
Chicopee Municipal Lighting Plant	O
Concord Municipal Light Plant	O
Conn. Municipal Electric Energy Coop.	F
Georgetown Municipal Light Department	O
Groton Electric Light Department	O
Groveland Electric Light Department	O
Hingham Municipal Lighting Plant	O
Holden Municipal Light Department	O
Holyoke Gas & Electric Department	O
Hudson Light and Power Department	O
Hull Municipal Lighting Plant	O
Ipswich Municipal Light Department	O
Littleton (MA) Electric Light Department	O
Mansfield Municipal Electric Dept.	O
Marblehead Municipal Light Dept.	O
Mass. Municipal Wholesale Electric Co.	O
Merrimac Municipal Light Department	O
Middleborough Gas and Electric Dept.	O
Middleton Municipal Electric Dept.	O
New Hampshire Electric Coop., Inc.	O
Pascoag Utility District	O
Paxton Municipal Light Department	O
Peabody Municipal Light Plant	O
Princeton Municipal Light Department	O
Reading Municipal Light Department	O
Rowley Municipal Lighting Plant	O
Russell Municipal Light Department	O
Shrewsbury's Electric & Cable Ops	O
South Hadley Electric Light Dept.	O
Sterling Municipal Electric Light Dept.	O
Stowe (VT) Electric Department	A
Taunton Municipal Lighting Plant	O
Templeton Municipal Lighting Plant	O
Vermont Electric Cooperative	A
Vermont Public Power Supply Authority	A
Wakefield Municipal Gas & Light Dept.	O
Wallingford, Town of	O
Wellesley Municipal Light Plant	O
West Boylston Municipal Lighting Plant	O
Westfield Gas & Electric Light Dept.	O
IN FAVOR (F)	2
OPPOSED (O)	38
TOTAL VOTES	40
ABSTENTIONS (A)	3

END USER SECTOR

Participant Name	VOTE
511 Plaza, LP	A
Cianbro Companies	A
Conn. Office of Consumer Counsel	F
Conservation Law Foundation	F
Dragon Products Company	A
Elektrisola, Inc.	A
Fairchild Semiconductor Corporation	A
Hardwood Products Company	A
Harvard Dedicated Energy Limited	F
High Liner Foods (USA) Inc.	A
Industrial Energy Consumer Group	A
Maine Public Advocate Office	F
Maine Skiing, Inc.	A
Marden's Inc.	A
Mass. Attorney General's Office	F
MoArk, LLC	A
NH Office of Consumer Advocate	F
PalletOne of Maine	A
PowerOptions, Inc.	F
Praxair, Inc.	A
St. Anselm College	A
Shipyards Brewing Co., LLC	A
The Energy Consortium	F
Union of Concerned Scientists	F
Utility Services Inc.	A
Westerly Hospital, The	A
Z-TECH, LLC	A
IN FAVOR (F)	9
OPPOSED (O)	0
TOTAL VOTES	9
ABSTENTIONS (A)	18

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