August 19, 2011

VIA ELECTRONIC FILING

Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1-A
Washington, DC 20426

Re: ISO New England Inc., Docket No. ER11-____-000
Order No. 745 Compliance Filing (Part 1 of 2)

Dear Secretary Bose:

ISO New England Inc. (the "ISO") hereby submits its filing in compliance with the Federal Energy Regulatory Commission's ("Commission's") Final Rule on Demand Response Compensation in Organized Wholesale Energy Markets ("Order No. 745").[1] As discussed below, the ISO proposes a two-stage implementation process that would put in place an initial set of demand response compensation rules on June 1, 2012 (the "transition period" rules) to be replaced by a second set of rules that would fully integrate demand resources into the energy market effective as of June 1, 2015 (the "fully integrated" rules). In support of this compliance filing, the ISO is submitting the testimonies of Henry Y. Yoshimura, Director, Demand Resource Strategy (the "Yoshimura Testimony") and David LaPlante, Vice President, Market Monitoring (the "LaPlante Testimony").[2]

As discussed further in Section VI of this filing, the ISO requests that the Commission issue an order in this proceeding as early as possible and no later than November 18, 2011.

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[1] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, III FERC Stats. & Regs., Regs. Preambles ¶ 31,322, 76 Fed. Reg. 16658 (2011) (Order No. 745).

[2] This filing letter and attachments are the first part of a two-part submission. Due to technical limitations associated with the Commission's eTariff system, the ISO is not able to submit multiple changes to the same tariff section that have different effective dates in one submission. Accordingly, the first part of the ISO's overall submission includes the tariff changes that are proposed to become effective on June 1, 2012. The second part of the ISO's overall submission includes the tariff changes that are proposed to become effective on June 1, 2015. The explanation and supporting materials for all of the tariff changes is contained in the first submission. Although the overall filing has been divided into two parts to accommodate the eTariff system, the Commission should treat the submissions as a single filing.

I. BACKGROUND

On March 18, 2010, the Commission issued a proposed rulemaking concerning the appropriate compensation for demand resources participating in organized wholesale energy markets.[3] Among other things, the Commission sought public comment on: (1) whether demand response providers should be paid the full locational marginal price ("LMP") for demand reductions, and; (2) whether full LMP payment should apply in all hours. On August 2, 2010, the Commission issued a Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference seeking additional comment concerning: (1) the use of a consumer "net benefits test" for purposes of determining when to pay the full LMP to demand response providers, and; (2) how the costs associated with payment of the full LMP for demand reductions should be allocated.[4]

On March 15, 2011, the Commission issued the final rule on demand response compensation ("Order No. 745"). Order No. 745 generally adopted the requirement to pay full LMP for demand response, but instead of requiring payment of the full LMP for all hours, the final rule mandated the use of a consumer "net benefits test" so that the full LMP is paid when the overall consumer benefit from reduced LMPs resulting from dispatching demand resources is likely to exceed the cost of paying demand response providers.[5] The payment of the full LMP is linked to the ability of a demand resource to "displace a generation resource in a manner that serves the RTO or ISO in balancing supply and demand."[6] Order No. 745 also required each ISO/RTO to explain the measurement and verification methods used to ensure the setting of appropriate consumption baselines. Finally, the final rule requires that the costs associated with demand response payments be allocated "proportionately to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched."[7]

The remainder of this filing describes the ISO's approach to complying with the requirements of Order No. 745.

II. COMPLIANCE APPROACH

The ISO and stakeholders in New England faced a number of complexities in determining the best approach to complying with Order No. 745. Order No. 745 specifically applies only in regions that have tariff provisions allowing for the participation of demand

[3] *Demand Response Compensation in Organized Wholesale Energy Markets*, Notice of Proposed Rulemaking, 130 FERC ¶ 61,213 (2010).

[4] *Demand Response Compensation in Organized Wholesale Energy Markets*, Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference, 132 FERC ¶ 61,094 (2010).

[5] Order No. 745 at P 2, 4-6.

[6] Order No. 745 at P 48.

[7] Order No. 745 at P 102.

resources in the energy market.[8] The ISO Tariff[9] currently includes provisions governing the participation of demand resources in the energy market. However, the demand response energy market provisions, by the explicit terms of the ISO Tariff, are effective only through May 31, 2012.[10] Absent a filing by the ISO and action by the Commission, there would be no demand response energy market tariff provisions for New England as of June 1, 2012.

The existing tariff provisions, which were implemented on March 1, 2003, put in place the New England region's first year-round demand response energy market program at the wholesale level.[11] The initial tariff provisions have been adjusted from time to time, but the overall structure of those early programs has remained the same. The current day-ahead and real-time demand response programs provide an opportunity for demand response providers to participate in the regional wholesale market. However, due to the limits of the existing market and system operations infrastructure, under the current programs demand response is not fully integrated into the market-clearing mechanisms, which limits the economic benefit that demand resources can provide through the wholesale energy markets. Accordingly, in the ISO's view the existing tariff provisions do not provide an appropriate structure upon which to achieve the long-term goal of fully integrating demand resources into the market.

Prior to the March 2010 initiation of the rulemaking proceeding that resulted in the issuance of Order No. 745, the ISO and stakeholders were engaged in considering the long-term structure of price-responsive demand in New England.[12] Those discussions were prompted

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[8] The new regulatory text adopted pursuant to Order No. 745 provides that the demand response market design elements mandated by the Commission apply to:

> Each Commission-approved independent system operator or regional transmission organization that has a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals….

18 C.F.R. § 35.28(g)(1)(v) (2011).

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

[10] ISO Tariff, Section III.E.1.3 (Appendix E, Load Response Program).

[11] Prior to March 1, 2003, the New England region periodically had adopted limited, temporary demand response programs targeted at achieving demand reductions during summer peak periods. *See, e.g., New England Power Pool*, Revisions to NEPOOL Market Rules to Modify, Enhance and Extend the Load Response Program, Transmittal Letter, Docket No. ER02-656-000 (Dec. 28, 2001).

[12] *See, e.g., ISO New England Inc. and New England Power Pool*, Tariff Revisions Regarding Extension of the Real-Time Price Response Program and Day-Ahead Load Response Program; Docket No. ER09-1737-000, Transmittal Letter at p. 6 and Laurita Testimony at p. 10, Docket No. ER09-1737 (Sept. 23, 2009); *Report of ISO New England Inc. and New England Power Pool Regarding Treatment of Price-Responsive Demand in the New England Electricity Markets*, Docket No. ER08-830-002 (July 31, 2009).

partly by the scheduled expiration of the current demand response programs on May 31, 2010.[13] The discussions ultimately resulted in stakeholders voting on several market design proposals, but not actual market rules, in December 2009.[14] Subsequently, the ISO developed draft market rules and presented them to the NEPOOL Markets Committee on March 10, 2010. The ISO's draft rules did not propose to amend the existing tariff provisions regarding demand response contained in Appendix E but, instead, proposed to amend Market Rule 1 to directly incorporate the treatment of demand resources into the main body of the energy market rules. The ISO's proposal would have resulted in significant changes to the way that demand resources participate in the wholesale energy market.

When Order No. 745 was issued on March 15, 2011, the ISO and stakeholders had to consider the most appropriate approach for developing tariff provisions that would comply with the final rule in light of the expiration of the current demand response programs in 2012 and the contextual background, unique to New England, described above. Ultimately, the ISO recommended that the New England region proceed with a two-stage implementation process consisting of new transition period rules that would go into effect on June 1, 2012, to be replaced by a second set of rules that would fully integrate demand resources into the energy market as of June 1, 2015. The ISO presented this compliance package at the NEPOOL Participants Committee meeting on April 1, 2011. The ISO's presentation identified the ultimate goal of fully integrating demand resources into the energy market and system dispatch, but noted that this goal would require a multi-year effort. Accordingly, the ISO indicated that the compliance filing would need to include rules for a transitional period until the fully integrated rules could be implemented. During the stakeholder discussions that followed and the development of rules for the compliance filing, the ISO sought to ensure that stakeholders (and, ultimately, the Commission) would be able to consider how all of the important aspects of the demand response rules would work together as a comprehensive package. This approach is reflected in the package of tariff changes submitted in this filing.[15]

The following section of this transmittal letter describes the new transition period rules that are proposed to become effective when the existing demand response rules expire on June 1, 2012, preceded by a description of the fully integrated rules that are proposed to become effective and replace the transition period rules on June 1, 2015.

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[13] *Id.*, Transmittal Letter at p. 6. The Commission accepted the two-year extension of the programs (to June 1, 2012) by letter order issued on October 29, 2009 in Docket No. ER09-1737.

[14] *Report of ISO New England Inc. and New England Power Pool Regarding Treatment of Price-Responsive Demand in the New England Electricity Markets*, Docket No. ER08-830-000 (December 18, 2009).

[15] As discussed later in this filing, there are certain additional demand-response related market design issues that the ISO and stakeholders have identified but, as a practical matter, were not able to fully consider and resolve in the limited time available before the compliance filing deadline. The ISO and stakeholders will be reviewing these issues in the coming months and expect to file any rule changes by January 2012.

III. DESCRIPTION OF THE COMPLIANCE RULES

Fully Integrated Rules

The core of the ISO's compliance approach is the decision to adopt a market design that will fully integrate demand resources into the energy markets. The full integration of demand resources into the energy markets requires the implementation of new market and system operation functions that will treat a Demand Reduction Offer for a demand resource in the same manner as a Supply Offer for a generator. These offers for both generation and demand resources will be used as part of the security-constrained economic dispatch system to identify the optimal set of demand and generation resources that minimizes production costs subject to reliability constraints. This approach best meets the requirement of Order No. 745 that demand resources be used to help balance supply and demand.[16] In order to implement this approach, Sections III.E.3 and III.E.4 of the fully integrated rules establish a structure through which demand response providers may submit Demand Reduction Offers and may specify operating parameters for their resources for both the day-ahead and real-time markets. Section III.E.5 specifies how Demand Reduction Offers are integrated into the scheduling and dispatch process. As required by Order No. 745,[17] Section III.E.9 of the fully integrated rules provides that demand response providers are paid the full LMP for their demand reductions.

Order No. 745 recognizes the importance of ensuring that demand resources are capable of contributing to the balancing of supply and demand in return for being eligible for energy market compensation at the full LMP.[18] Accordingly, Sections III.E.1 and III.E.2 of the fully integrated rules establish the registration, metering, audit and related rules that are used to measure and verify the demand reduction contributions of demand resources.[19] Among other things, these rules require that demand resource performance be measured at the retail delivery point, which effectively is the point of interconnection with the New England Control Area and the point at which the ISO observes the resource's contribution to balancing supply and demand.[20]

Order No. 745 requires that the costs associated with demand response compensation be allocated proportionally to all entities that purchase from the relevant energy market in the areas where demand response reduces the market price for energy when the demand resource is

[16] Order No. 745 at P. 48.

[17] Order No. 745 at PP 47-48.

[18] Order No. 745 at P 47.

[19] Developing an accurate baseline that reflects the normal operating condition of a demand resource is a critical aspect of determining demand resource performance and the metering, audit and related rules are closely associated with the development of an accurate baseline. The baseline accuracy rules to be used under both the transition period and fully integrated rules are discussed later in this transmittal letter.

[20] Yoshimura Testimony at pp. 18-27.

committed or dispatched.[21] Section III.E.9.3 of the fully integrated rules provides that charges or payments resulting from real-time demand reductions produced by demand resources will be allocated on an hourly basis proportionally to Real-Time Load Obligation on a system-wide basis. As explained in the Yoshimura Testimony, a system-wide allocation of demand response costs is appropriate because: (1) demand resources are located throughout the New England region; (2) demand reductions are likely to impact LMPs beyond the specific node at which the reduction occurs, and; (3) it would be extremely difficult to attempt to identify (and allocate) specific costs based on analysis of price impacts on a nodal or even sub-regional basis.[22] The two exceptions to the cost allocation rule involve Real-Time Load Obligation incurred at External Nodes and by Dispatchable Asset Related Demand postured by the ISO. The External Node exclusion is intended to avoid imposing costs on energy traded between regions and, potentially, restricting that trade.[23] In addition, the New England region will be the primary beneficiary of demand reductions within the region, rather than external regions represented by the External Nodes.[24] The Dispatchable Asset Related Demand exclusion is appropriate because a Market Participant with a Dispatchable Asset Related Demand (typically a pumped storage hydro unit) that is postured by the ISO (*i.e.*, directed to pump water into a reservoir for reliability purposes) is not charged for energy based on the LMP, but is charged based on the resource's Demand Bid. Under such circumstances, the Market Participant does not benefit from any changes to the LMP associated with demand resources.[25]

<u>Transition Period Rules</u>

The transition period rules include many components of the fully integrated rules, including provisions: (i) requiring that Demand Reduction Offers exceed the Demand Reduction Threshold Price; (ii) applying an improved baseline methodology; (iii) compensating demand reductions delivered in real time that are consistent with the amounts offered and scheduled in response to LMPs; and (iv) allocating costs associated with payments for demand reductions proportionally to entities purchasing from the relevant energy market in the area where the demand reduction reduces the market price for energy.[26]

The transition period rules vary from the fully integrated rules in the following respects:

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[21] Order No. 745 at P 100.

[22] Yoshimura Testimony at pp. 65-66.

[23] Yoshimura Testimony at p. 65.

[24] *Id.*

[25] Yoshimura Testimony at pp. 65-66.

[26] Yoshimura Testimony at pp. 67-69..

- the ISO will not be able to accept offers associated with demand resources consisting of an aggregation of assets during the transition period;[27]

- two-way, real-time communication of energy market Dispatch Instructions will not be utilized between the ISO and a Market Participant with demand resources, and no real-time dispatch of Real-Time Demand Response Assets will occur;[28] instead, the Market Participant will be obligated to provide demand response in accordance with the schedule it receives through participation in the Day-Ahead Energy Market;[29]

- Demand Reduction Offers will only be accepted on a day-ahead basis, with only one price/demand-reduction quantity pair for each asset, and with only two other bid parameters (compared with a broader array of bid parameters in the fully integrated rules);[30]

- the Day-Ahead Energy Market solution will be derived before consideration of Demand Reduction Offers, and the resulting Day-Ahead LMPs will then be used to determine the clearing of those offers in the Day-Ahead Energy Market;[31]

- the Real-Time Demand Reduction Obligation of a Real-Time Demand Response Asset will be capped at 200% of the associated Demand Reduction Offer amount adjusted for avoided distribution losses, in order to provide incentives for Market Participants to follow their cleared day-ahead demand reduction schedules;[32] and

- the transition period rules do not incorporate Net Commitment Period Compensation ("NCPC"), since NCPC credits and charges are applicable solely to resources that are fully integrated into the energy market clearing and dispatch processes.[33]

The transition period rules also include changes to Appendix A of Market Rule 1 giving the ISO's Internal Market Monitor the ability to obtain Market Participant data that will assist it in monitoring resource performance and demand response provider behavior.[34] The ISO New

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[27] Yoshimura Testimony at p. 69.

[28] Yoshimura Testimony at pp. 69-70.

[29] Yoshimura Testimony at pp. 72-73.

[30] Yoshimura Testimony at pp. 70-71.

[31] Yoshimura Testimony at p. 73.

[32] Yoshimura Testimony at pp. 74-77.

[33] Yoshimura Testimony at pp. 78-79.

[34] LaPlante Testimony at pp. 3-5.

England Information Policy will reflect a corresponding modification so that information provided in response to an Internal Market Monitor data request will be considered Confidential Information under the policy.[35]

Demand Reduction Threshold Price

Order No. 745 requires the use of a consumer net benefits test so that demand response providers generally only are dispatched and paid the market price for energy when the overall benefit to consumers of the reduced LMP that results from dispatching demand resources exceeds the cost of payments for those resources.[36] The Commission requires that the net benefits test be implemented in the form of a monthly threshold price, based on historical data and updated to reflect relevant supply conditions. The threshold price is to be the point on the supply curve beyond which the overall consumer benefit from the reduced LMPs associated with dispatching demand resources exceeds the costs of payments to those resources.[37] Section III.E.6 of the fully integrated rules specifies how the ISO will calculate and use a monthly Demand Reduction Threshold Price as required by Order No. 745.

The ISO's proposed tariff provisions require that a Demand Reduction Threshold Price be established for each month using a regression-based approximation method on a sampled portion of Supply Offer data (*i.e.*, each price-quantity pair offered in the Real-Time Energy Market) for the historical reference month.[38] The proposed market rules require that the regression produce an increasing, convex, smooth approximation of the supply curve so as to ensure that a unique Demand Reduction Threshold Price is obtained for each month.[39] The Demand Reduction Threshold Price for the historical reference month is the price at which the slope of the smooth approximation function equals P/x, where P is the price (in $ per MWh) and x is the aggregate MW supplied.[40] The Demand Reduction Threshold Price for the upcoming month is based on the historical threshold price for the same month of the previous year adjusted for any substantial changes in supply availabilities and for differences in fuel price indices between the historical month and the current month.[41]

The ISO plans to post on the ISO's website on a monthly basis the supply curve analysis used to determine Demand Reduction Threshold Prices. In addition to the resulting Demand Reduction Threshold Price for the upcoming month, the posting will include:

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[35] LaPlante Testimony at p. 8.

[36] Order No. 745 at P 47.

[37] Order No. 745 at P 4.

[38] Yoshimura Testimony at p. 39.

[39] *Id.*

[40] *Id.*

[41] Yoshimura Testimony at pp. 39-40.

- The functional form used to establish the smoothed supply curve.

- The historical reference month supply curve data in the form of market-level price/quantity pairs. These data will ***not*** identify the resource associated with each price/quantity pair.

- The relevant sample range, estimated regression coefficients, and associated statistics such as R-Square.

- Any adjustments that were made for significant changes to the composition or slope of the historical monthly supply curves.

- Any adjustments that were made for changes in the fuel price index.[42]

The ISO includes as part of the Yoshimura Testimony the required 12 months of sample Demand Response Threshold Prices computed using the foregoing methodology, for the January to December 2010 period.[43]

Assuring the Use of Accurate Baselines

Order No. 745 mandates an evaluation of any existing measurement and verification rules for demand resources and the development of appropriate modifications, if necessary, to ensure that demand resource baselines remain accurate when the monthly threshold price mechanism is implemented.[44] The ISO retained KEMA Inc. ("KEMA") to assist in evaluating the existing measurement and verification requirements used in New England and in recommending a baseline methodology for use in the transition period and fully integrated rules that will ensure that baselines (and the associated demand reduction calculations) remain accurate and unbiased. The Yoshimura Testimony details the results of the KEMA analysis and discussions with stakeholders concerning baseline accuracy measures.[45] Ultimately, the ISO's review indicated that the baseline methodology that is currently used in New England, combined with a symmetrical baseline adjustment as explained in the Yoshimura Testimony,[46] generally compares favorably to alternative methodologies in terms of accuracy, bias and variability. Accordingly, the ISO generally proposes to use the existing methodology, with certain limited

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[42] Yoshimura Testimony at p. 40.

[43] Yoshimura Testimony at Exhibit B. *See* Order No. 745 at P 81.

[44] Order No. 745 at P 94.

[45] Yoshimura Testimony at pp. 49-55.

[46] Yoshimura Testimony at p. 50.

changes. The baseline methodology to be used under the transition period and fully integrated rules is set out in a new Section III.8 of Market Rule 1.[47]

A demand response baseline generally is an estimate of a consumer's likely energy consumption for each interval of the current operating day based on interval meter data from previous days. In order to ensure that the baseline for a particular demand resource remains accurate, the baseline must be refreshed regularly with recent meter data reflecting the normal operating condition of the resource for the current period or season. Under the existing demand response rules that are expiring in 2012, the availability of recent meter data is ensured by using a bidding threshold price that prevents demand resources from clearing too frequently.

The new transition period and fully integrated rules do not use a bidding threshold price to ensure the availability of recent meter data reflecting normal operating conditions. Instead, under the new rules,[48] in order for a demand resource to be eligible to provide a demand reduction, at least three of the last 10 days of the resource's meter data must reflect days under normal operating conditions during which the resource did not provide demand reductions. KEMA's analysis showed that this "3 of Last 10 Days" methodology (coupled with use of a symmetric baseline adjustment) should produce better results than alternative methodologies. There was a preference expressed during the stakeholder review process, including from stakeholders representing demand response provider, for this methodology because it is more transparent and should allow for easier management of demand resources than alternatives that use a bidding threshold price.

The ISO proposes, under both the transition period and fully integrated rules, a baseline computation that differs in three respects from the computation used under the existing demand response programs. First, a symmetric baseline adjustment will be used instead of the current asymmetric baseline adjustment.[49] This adjustment will take account of the fact that conditions affecting energy consumption in the current operating day may vary from conditions affecting consumption on the previous days from which meter data was used to compute the baseline. A symmetric adjustment will appropriately adjust the baseline in either the upward or downward direction depending on the metering results.

Second, baseline bias will be reduced by requiring that the calculated baseline be periodically refreshed with contemporary meter data.[50] This will ensure that the baseline reflects the expected demand of a participating customer absent demand reductions in response to price signals. Otherwise, as KEMA's analysis demonstrates, if a Market Participant submits Demand Reduction Offers persistently at the Demand Reduction Threshold Price, these offers would clear virtually every day of the year. Excluding the cleared days from the baseline computation (as is

[47] ISO Tariff, Section III.8.

[48] The new baseline calculation methodology is contained in Section III.8 of Market Rule 1.

[49] Yoshimura Testimony at pp. 51-55.

[50] Yoshimura Testimony at pp. 59-64.

done under current rules) could make the data used to establish the baseline very stale and not reflective of normal operating conditions for the current period within which a Demand Reduction Offer is submitted. For example, the baseline used to estimate expected demand absent demand reductions in response to price signals in the fall and winter could be based on summer meter data.

Third, the number of days of meter data needed to establish an initial Demand Response Baseline for a new Demand Response Resource will be 10 continuous days of the same day-type.[51] This requirement is necessary because the "3 of Last 10 Days" methodology described above requires at least 10 days of meter data to develop the Demand Response Baseline in the first place. Moreover, increasing the sample size upon which to estimate the expected demand of a participating customer absent demand reductions in response to price signals always improves the statistical confidence of the estimate.

IV. PLANNED ADDITIONAL DEMAND RESPONSE-RELATED RULE CHANGES

The ISO and stakeholders identified a number of additional demand response-related market design issues that, while not required for compliance, but are expected to be reviewed and addressed in the near future. These issues involve changes to the Forward Capacity Market ("FCM") rules[52] and additional changes to energy market rules applicable to demand resources with Capacity Supply Obligations. Some of the issues that are expected to be included in the stakeholder discussions are:

- changes to make the FCM rules consistent with the proposed energy market rules with respect to demand resource qualification, metering requirements, baseline and performance calculations;
- whether demand response providers should be required to submit Demand Reduction Offers for demand resources with Capacity Supply Obligations (*i.e.*, a "must offer" requirement);
- whether to change the manner in which demand resources with a Capacity Supply Obligation will be dispatched (*i.e.*, rather than dispatching demand resources in response to a capacity deficiency, dispatch demand resources based on its offer price in the energy market);
- whether energy market payments associated with demand resources with Capacity Supply Obligations are subject to the Peak Energy Rent deduction, and;

[51] Yoshimura Testimony at pp. 62-64.

[52] ISO Tariff, Section III.13.

- the provision of energy payments, based on the appropriate real-time LMP, for demand resources that are dispatched or audited pursuant to Section III.13 of the ISO Tariff.

The ISO initiated stakeholder discussions of these issues at the NEPOOL Markets Committee meeting held on August 17-19, 2011. The ISO currently expects to complete the stakeholder review process for these additional issues in January 2012 and to submit a tariff change filing to the Commission in the same month. Tentatively, the proposed effective date for the additional rules would likely be on or about April 1, 2012, which is before the administration of the Forward Capacity Auction for the 2015/2016 Capacity Commitment Period.

The ISO also has identified several other demand response-related market design changes that it expects to review with stakeholders in the next year or so. First, the ISO has initiated further review of the baseline adjustment mechanism to determine if an alternative to the symmetric adjustment method would be appropriate for certain types of demand resources, particularly demand resources that are associated with industrial customers that use shifts of workers.[53] Second, the ISO is planning to initiate stakeholder discussions in 2012 concerning potential market changes to allow Market Participants with dispatchable resources, including demand response providers, to submit hourly energy offers and modify the commitment cost components and the incremental energy-offer component during the operating day. In common with most other regions, the current energy market infrastructure in New England is not able to accommodate changes to certain offer parameters during the operating day. Developing hourly offer capability is a complex undertaking for a number of reasons, including the need to address baseline and market monitoring-related issues. While the schedule is subject to change, the ISO's current goal is to develop rules for hourly energy offer capability that could be implemented in 2015 coincident with the implementation of the fully integrated approach to price-responsive demand.

V. STAKEHOLDER PROCESS

The NEPOOL Markets Committee first considered Order No. 745 compliance issues at its meeting on April 6, 2011 and completed its review over the course of seven meetings. The ISO presented its proposed Order No. 745 compliance package to the NEPOOL Markets Committee for vote at the committee's July 19-20, 2011 meeting. At that meeting, the Markets Committee voted and failed to support two compliance packages. The Markets Committee failed by a vote of 39.78% in favor to support a compliance package that included an amendment limiting to 150% the amount by which a real-time demand reduction could exceed the related day-ahead offer amount and still be eligible for compensation. The Markets Committee also failed by a vote of 48.71% in favor to support the ISO's proposed compliance package, which differed from the first package only in that it provided for a 200% limit on the amount by which

[53] Yoshimura Testimony at pp. 58-59.

a real-time demand reduction could exceed the day-ahead offer amount and be eligible for compensation.

The ISO's compliance package was considered by the NEPOOL Participants Committee at its August 12, 2011 meeting. Similar to the Markets Committee, the Participants Committee considered several stakeholder amendments, but none of the amendments were adopted. The Participants Committee ultimately voted on the ISO's unamended compliance package, which it failed to support by a vote of 51.9% in favor.

VI. REQUESTED EFFECTIVE DATE AND COMMISSION ACTION DATE

The ISO requests an effective date of June 1, 2012 for the transition period rules and June 1, 2015 for the fully integrated rules.

The ISO requests that the Commission issue an order addressing the compliance filing no later than November 18, 2011 (approximately 90 days after submission of the filing). Issuance of an order by this date will assist both the ISO and stakeholders in their efforts to prepare for the implementation of the new transition rules on June 1, 2012 and the fully integrated rules on June 1, 2015. Depending on the substance of the Commission's order and the scope of any additional compliance requirements, issuing an order after November 18, 2011 could create a substantial risk that the transition period rules could not be finalized and implemented before the expiration of the existing demand response programs on May 31, 2012. In addition to further market rule development and stakeholder review process that could be required depending on the substance of the Commission's order on the compliance filing, detailed manuals and operating procedures, business processes, software (including testing protocols), and training materials that are consistent with the Commission's order must be developed and implemented prior to May 2012.

Additionally, by issuing an order by November 18, 2011, the Commission would also assist the ISO, demand response providers and other stakeholders in making important decisions during December 2011, potentially including decisions regarding participation in the Forward Capacity Auction for the 2015/2016 Capacity Commitment Period that will be held in April 2012. Specifically, by issuing an order on or before November 18, 2011, the Commission will permit the ISO and stakeholders to take account of the results of the order *before* taking actions in response to two important milestones in early December. The first milestone is the planned December 6-7, 2011 vote of the NEPOOL Markets Committee on the additional demand-response related market rules discussed in Section IV of this transmittal letter. The Commission's order in this proceeding may affect the positions of both the ISO and stakeholders concerning the substance of these additional changes. The second milestone is the release of Notifications of FCA Qualified Capacity on December 16, 2011. After considering the Commission's order in this proceeding, a demand response provider could withdraw a New Resource within five days after the notification date and avoid posting financial assurance.

VII. DESCRIPTION OF THE ISO; COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the ISO Tariff and the Transmission Operating Agreement with the New England transmission owners. In its capacity as an RTO, the ISO also has the objective to assure that the bulk power supply system within the New England Control Area conforms to proper standards of reliability as established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

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

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VIII. **ADDITIONAL SUPPORTING INFORMATION**

Please find the following materials attached hereto:

- Attachment 1: Redlined substitute tariff sheets in response to the requirements of Order No. 745 for the transition period rules;
- Attachment 2: Clean substitute tariff sheets in response to the requirements of Order No. 745 for the transition period rules;
- Attachment 3: Redlined substitute tariff sheets in response to the requirements of Order No. 745 for the fully integrated rules (included in Part 2 of this submission);
- Attachment 4: Clean substitute tariff sheets in response to the requirements of Order No. 745 for the fully integrated rules (included in Part 2 of this submission);

- Attachment 5: Testimony of Henry Y. Yoshimura in support of the changes to Market Rule 1, Appendix E and related provisions, including Exhibit A (CRA Report re Demand Reduction Threshold Price), Exhibit B (ISO Analysis re Supply Curve Smoothing and Demand Reduction Threshold Price Estimates) and Exhibit C (KEMA Report re Baseline Accuracy Methodology) thereto;

- Attachment 6: Testimony of David LaPlante in support of the changes to Market Rule 1, Appendix A and the ISO New England Information Policy; and;

- Attachment 7 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 electronically.

IX. CONCLUSION

The ISO requests that the Commission accept the Order No. 745 compliance filing package as submitted, and without modification or condition, to be effective as of June 1, 2012, for the transition period rules, and June 1, 2015, for the fully integrated rules. The ISO also requests that the Commission issue an order in this proceeding no later than November 18, 2011.

Respectfully submitted,

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Attachments and Exhibits

Attachment 1

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:

Accepted Electric Industry Practice, sometimes referred to as Good Utility Practice, means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric generation and transmission 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. Accepted Electric Industry Practice is not limited to a single, optimum practice method or act to the exclusion of others, but rather is intended to include practices, methods, or acts generally accepted in the region.

Adjusted Regulation Obligation is equal to a Market Participant's total Real-Time Load Obligation ratio share of the total amount of Regulation provided that hour, adjusted for any internal bilateral transactions for Regulation.

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.

Amount Interrupted is, for purposes of the Load Response Program, the calculated difference between the Customer Baseline and the actual customer load. For generating assets, metered at the generator output, the Amount Interrupted is the generator output.

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, 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 electricity 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.

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; (iii) the sum of a Critical Peak Demand Resource's electrical energy reduction during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours less 30 minutes for each set of consecutive Real-Time Demand Resource Dispatch Hours within the same Operating Day in the month for that resource; or (iv) 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. 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; (iii) the sum of a Critical Peak Demand Resource's electrical energy output during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours for that resource less 30 minutes for each set of consecutive Real-Time Demand Resource Dispatch Hours within the same Operating Day in the month for that resource; or (iv) 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.

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 the 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); and (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).

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 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 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 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 a load serving entity's initially allocated share of the Installed Capacity Requirement, prior to any Capacity Load Obligation Bilaterals, during a Capacity Commitment Period for a Capacity Zone, as 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.

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

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 the other Covered Entities and for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the generation output level, expressed in MW, which can be reached by a Resource (from an off-line state) within 10 minutes after receiving a Dispatch Instruction or the amount of reduced consumption, expressed in MW, which can be reached by a Dispatchable Asset Related Demand within 10 minutes after receiving a Dispatch Instruction. A CLAIM10 value is required as part of a Resource's or Dispatchable Asset Related Demand's Offer Data. CLAIM10 values are established pursuant to the provisions of Section III.9.5.3.

CLAIM30 is the generation output level, expressed in MW, which can be reached by a Resource (from an off-line state) within 30 minutes after receiving a Dispatch Instruction or the amount of reduced consumption, expressed in MW, which can be reached by a Dispatchable Asset Related Demand within 30 minutes after receiving a Dispatch Instruction. A CLAIM30 value is required as part of a Resource's or Dispatchable Asset Related Demand's Offer Data. CLAIM30 values are established pursuant to the provisions of Section III.9.5.3.

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.

Commitment Offer Test is defined in Section III.A.5.8.3 of Appendix A of Market Rule 1.

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 weekly 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, for purposes of Section II of the Tariff, 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 Council; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Area, for purposes of Section III of the Tariff, is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: (i) 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); (ii) maintain scheduled interchange with other Control Areas, within the limits of Accepted Electric Industry Practice; (iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the applicable regional reliability council or the NERC; and (iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry 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 determined in accordance with Section III.13.2.4 of Market Rule 1.

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.

Critical 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 electrical usage during Demand Resource Critical Peak Hours or shift electrical usage from Demand Resource Critical Peak Hours to other hours and reduce the amount of capacity needed to deliver a comparable or acceptable level of service at those end-use customer facilities. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

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

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

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

Customer Baseline is the average aggregate hourly load, rounded to the nearest kWh, for each of the 24 hours in a day for each Load Response Program Asset participating in the Real-Time Price Response Program, and the average aggregated five-minute load, rounded to the nearest kWh, for each of the 24 hours in a day for Real-Time Demand Response Assets and Real-Time Emergency Generation Resource assets.

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.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(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 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.

Demand Reduction Value is the quantity of reduced demand, measured at the end-use customer meter, produced by a Demand Resource, which is calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

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

Demand Resource is a resource defined as On-Peak Demand Resources, Seasonal Peak Demand Resources, Critical 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 during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Demand Resource Critical 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 Critical Peak Hours means Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours.

Demand Resource Financial Assurance Requirement is an amount of financial assurance required from DRP-Only Customer registering a Demand Resource in the Day-Ahead Energy Market. This amount is calculated pursuant to Section VIII.A of the ISO New England Financial Assurance Policy.

Demand Resource Forecast Peak Hours means those hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and Real-Time Demand Response Resources, 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, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours by 10:00 p.m. on the day before the relevant Operating Day. Beginning on June 1, 2011, **Demand Resource Forecast Peak Hours** are those hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and 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, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours by 10:00 p.m. on the day before the next Operating Day.

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-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 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.8.

Demand Response Holiday is a holiday for which a Market Participant may not submit a Demand Reduction Offer for a Real-Time Demand Response Asset.

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 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 or DRP-Only Customer 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 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 billing 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, Demand Resource Critical 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. Distributed Generation resources are not eligible for energy payments from ISO-administered energy markets. Generation resources cannot participate in the Forward Capacity Market as Demand Resources, unless they meet the definition of Distributed Generation.

DRP-Only Customer is a Market Participant that enrolls itself and/or one or more Demand Resources in the Load Response Program and that does not participate in other markets or programs of the New England Markets, provided, however, that a DRP-Only Customer may also be an FTR-Only Customer and/or an ODR-Only Customer. References in this Tariff to a Non-Market Participant demand response provider or similar phrases shall be deemed references to a DRP-Only Customer.

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 prices of 0.8 times CONE or lower, as described in Section III.13.2.3.2(d) of Market Rule 1.

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 – (average of max and min Effective Temperature of the day).

Effective Temperature is equal to dry bulb temperature – [windspeed X (65-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, for purposes of Section II of the Tariff, is an abnormal condition on the bulk power system(s) of New England and/or neighboring control areas that, if not immediately corrected, could lead to the shedding of firm electrical load. Such abnormal conditions are beyond the reasonable control and ability to avoid of the system operator of the region(s) experiencing such conditions. Such conditions could result from emergency outages of generating units, transmission lines or other equipment, or other such unforeseen circumstances such as load forecast errors.

Emergency, for purposes of Section III of the Tariff, is an abnormal system condition 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.

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.

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.

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.

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.

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.

FCM Pivotal Supplier shall mean a Lead Market Participant whose total Qualified Capacity from its Existing Capacity Resources in a Capacity Zone minus the quantity of its capacity subject to Non-Price Retirement Requests in that Capacity Zone for the current Forward Capacity Auction is greater than the difference between the total MW from qualified Existing Capacity Resources in the Capacity Zone minus the sum of the quantity of capacity subject to Non-Price Retirement Requests in that Capacity Zone plus the Local Sourcing Requirement for that Capacity Zone.

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 Critical Peak Demand Resource, Real-Time Demand Response Resource, and Real-Time Emergency Generation Resource, 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, provided, however, that an FTR-Only Customer may also be a DRP-Only Customer and/or an ODR-Only Customer. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

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

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

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

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

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

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

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

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

Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

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

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

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

Governance Participant is defined in the Participants Agreement.

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

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

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

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

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

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

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

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

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

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

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

Hourly Real-Time Emergency Generation Resource Deviation means the difference between the Average Hourly Output of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction 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.

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.

HQ Interconnection Excess is the difference between the HQ Interconnection transfer limit as determined by the ISO and the Commission approved MW value of Hydro Quebec Interconnection Capability Credits.

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.

Hydro Quebec Interconnection Capability Credits are credits that are granted to a Market Participant or group of Market Participants in accordance with the ISO New England System Rules, where the value of such credits is determined in accordance with the ISO New England Manuals.

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, a DRP-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Payment (ICAP Payment) means the monthly payments made to ICAP Resources for installed capacity during the ICAP Transition Period.

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.

Installed Capacity Resource (ICAP Resource) means a resource that met the requirements to receive installed capacity payments during the ICAP Transition Period.

Installed Capacity Transition Period (ICAP Transition Period) is December 1, 2006 through May 31, 2010.

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.

Investment Grade Rating, for a Market (other than an FTR-Only Customer or DRP-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 New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

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

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

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

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

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

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

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

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

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

ITC Agreement is defined in Attachment M to the OATT.

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

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

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

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

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

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

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers 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, Demand Resource Critical 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 Resource is defined in Section III.6.1 of Market Rule 1.

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.

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.

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.

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

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 and/or a DRP-Only Customer and/or an ODR-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 Generation is the maximum generation output of a Real-Time 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 can deliver.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, measured at the retail delivery point of a Real-Time Demand Response Asset.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Minimum 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.

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

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

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

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

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

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

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

MUI is the market user interface.

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

MW is megawatt.

MWh is megawatt-hour.

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

NCPC Charge means the charges to Market Participants 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 Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

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.13.2.4(c) of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource (including any payment as an ICAP Resource pursuant to the market rules in effect prior to December 1, 2006 or any ICAP Payment during the ICAP Transition Period pursuant to the market rules in effect from December 1, 2006 through May 31, 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 England Control Area, for purposes of Section II of the Tariff, is the Control Area (as defined in Section II.1.11) 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 Control Area, for purposes of Section III of the Tariff, is the integrated electric power system to which a common automatic generation control scheme and various operating procedures are applied by or under the supervision of the ISO in order to: (i) match, at all times, the power output of the generators within the electric power system and capacity and energy purchased from entities outside the electric power system, with the load within the electric power system; (ii) maintain scheduled interchange with other interconnected systems, within the limits of Accepted Electric Industry Practice; (iii) maintain the frequency of the electric power system within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the NPCC and NERC; and (iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry Practice.

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

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 calculated in accordance with Section VII.B.2(i) of the ISO New England Financial Assurance Policy.

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.

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.

ODR-Only Customer is a Market Participant that registers with the ISO an Other Demand Resource (as defined in Section III.1 of this Tariff) and that does not participate in other markets or programs of the New England Markets, provided, however, that a DRP-Only Customer may also be an FTR-Only Customer and/or an DRP-Only Customer.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand 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.

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 Demand Resource (ODR) is an installation undertaken as part of a merchant, utility, or state-sponsored program, and may include Energy Efficiency, Load Management, and Distributed Generation projects that are installed after June 16, 2006, and that result in additional and verifiable reductions in end-use customer demand on the electricity network in the New England Control Area during specified ODR performance hours of the ICAP Transition Period.

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.

Out-of-Market Capacity is certain capacity that is counted in determining whether the Alternative Capacity Price Rule applies, as described in Section III.13.2.7.8 of Market Rule 1.

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, as remitting agent for the Covered Entities.

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.

Pivotal Supplier is defined in Section III.A.5.2.2 of Appendix A of Market Rule 1.

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.

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.E.8.

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 Load Zone or system-wide basis, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours. Beginning on June 1, 2011, "Real-Time Demand Resource Dispatch Hours" shall be defined as 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 Critical Peak Demand Resources and 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 the hours, or portions thereof, when the ISO dispatches Real-Time Demand Response Resources in the Load Zone where a Demand Resource is located in response to Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours. Beginning on June 1, 2011, Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Demand Resource Forecast Peak Hours and 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 the output of one or more emergency generators 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 to curtail electric consumption. Real-Time Emergency Generation Resources would be dispatched by the ISO on a 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. Beginning on June 1, 2011, 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 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, 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 Accepted Electric Industry 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.

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.

Re-Offer Period is the period normally between 16:00 and 18:00 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.

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.

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.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer, a DRP-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 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.

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.

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.

SPD means the ISO's Scheduling, Pricing, and Dispatch software, as more fully described in Section III.A.5.5.3 of Appendix A of Market Rule 1.

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.

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.

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.

Submitted Offer is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

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 Margin is defined in Section III.A.5.2.2 of Appendix A 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 Restoration and Planning Service is the form of Ancillary Service described in Schedule 16 of the OATT. System Restoration and Planning Service is referred to as blackstart service.

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 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 Load Zone or, starting on June 1, 2011, 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 Load Zone or, starting on June 1, 2011, 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.

UCS is Unit Commitment Software as more fully defined in Section III.A.5.5.3 of Appendix A of Market Rule 1.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

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

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

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

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

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III.8 ~~[Reserved.]~~ Demand Response Baselines

A Demand Response Baseline is calculated for any Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that requires a baseline on a daily basis using five-minute meter data.

8.1 Establishing the Initial Demand Response Baseline

The Demand Response Baseline for a new Real-Time Demand Response Asset or Real-Time Emergency Generation Asset (an asset with no previously computed Demand Response Baseline) shall be the simple average of meter data for the asset for each five-minute interval from the initial ten non-Demand Response Holiday weekdays. The initial ten non-Demand Response Holiday weekdays of meter data used to establish the Demand Response Baseline shall consist of the first ten consecutive non-Demand Response Holiday weekdays with a complete set of interval meter data. A Market Participant may not submit Demand Reduction Offers until the month following the initial establishment of a Demand Response Baseline for an asset.

8.2 Establishing the Demand Response Baseline for the Present Day

If, for a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

(a) the asset has been dispatched or audited in the present day pursuant to Section III.13, or;
(b) the Demand Reduction Offer associated with the asset is eligible in the Operating Day for payments pursuant to Section III.E.9, then:

the asset's Demand Response Baseline, in each five-minute interval, for the present day is equal to the Demand Response Baseline, in the same five-minute interval from the prior day.

8.3 Establishing the Demand Response Baseline for the Next Day

If, for a Real-time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

(a) the asset has not been dispatched or audited in the present day pursuant to Section III.13, or;

(b) the Demand Reduction Offer associated with the asset is not eligible in any hour of the Operating Day for payments pursuant to Section III.E.9, or;

(c) the Demand Reduction Offer associated with the asset is eligible in the Operating Day for payments pursuant to Section III.E.9 and more than seven of the prior 10 non-Demand Response Holiday weekdays have a Demand Response Baseline determined pursuant to Section III.8.2, then:

the asset's Demand Response Baseline in each five-minute interval, for the next day is calculated as the sum of 0.9 times the asset's Demand Response Baseline in the same five-minute interval from the prior day and 0.1 times the asset's meter data in the same five-minute interval in the present day.

8.4 Baseline Adjustment

8.4.1 Baseline Adjustment for Real-Time Demand Reductions from Assets Without Generation

For each day the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset pursuant to Section III.E.8.1, the ISO will calculate an adjustment factor equal to the average difference (MW) between the asset's actual metered demand and its Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load.

8.4.2 Baseline Adjustment for Real-Time Demand Reductions from Assets with Generation

For each day the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset pursuant to Section III.E.8.2, the ISO will calculate an adjustment factor equal to the average difference (MW) between the sum of the asset's actual metered demand and the output of all generators located behind the asset's retail delivery point in the same time intervals and the asset's Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load, plus the output of all generators located behind the asset's retail delivery point in the same time intervals as the asset's Maximum Load.

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset that is comprised of a Distributed Generation asset located behind the retail delivery point of an individual end-use customer facility, the asset's Demand Response Baseline shall not be subject to the baseline adjustment.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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EXHIBIT 1 MARKET IMPACT AND NCPC THRESHOLDS

EXHIBIT 2 [Reserved]

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EXHIBIT 5 ISO NEW ENGLAND INC. CODE OF CONDUCT

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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

III.A.1.1. Mission Statement.

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

III.A.1.2. Structure and Oversight.

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

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

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III A.12.4 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

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

III.A.2. Functions of the Market Monitor

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

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

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.5.10 and Section III.A.7 of this ***Appendix A***). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

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

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

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

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

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlines in Sections III.A.14 and III.A.15 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.12 of this ***Appendix A***.

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

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.14 and/or III.A.15 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

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

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

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

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

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

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

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

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

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

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlines in Section III.A.14 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.14 and III.A.15 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

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

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.12 of this ***Appendix A***.

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

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

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

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

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

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.8 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.7 of this ***Appendix A.***

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

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

(i) Anti-competitive gaming of Resources;

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

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

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

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

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

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.12 of this ***Appendix A***. Monitoring under this Section III.A.2.3 (k) cannot serve as a basis for mitigation under III.A.8 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.2.5.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.7, or III.A.8. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

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

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

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

III.A.2.4.1.Purpose.

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

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

(a) *Imposing Mitigation*. To achieve the foregoing purpose and objectives, mitigation measures should only be imposed to remedy conduct that would substantially distort or impair the competitiveness of any of the markets administered by the ISO. Accordingly, and as more fully described in Sections III.A.5, III.A.8, and III.A.9 below, the ISO shall seek to impose mitigation measures only to remedy conduct that:

(i) is significantly inconsistent with competitive conduct as discussed below in Section III.A.2.4.2(b); and

(ii) would result in a change in one or more prices in the New England Markets or NCPC payments to a Market Participant beyond the thresholds defined in ***Exhibit 1***, Section III.A.5.3 or Section III.A.5.8 of this ***Appendix A***, as appropriate.

(b) *Conduct Inconsistent with a Competitive Market*. In general, the ISO shall consider a Market Participant's conduct to be inconsistent with competitive conduct if the conduct would (i) reduce the net revenue associated with the Resource, but for the effect of the conduct on market outcomes, or (ii) reduce the capability of the Transmission System resulting in a price impact in the New England Markets or NCPC payments in excess of either of the thresholds in ***Exhibit 1***, Section III.A.5.3 or Section III.A.5.8 of this ***Appendix A***, as appropriate.

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

III.A.2.4.3 Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4 Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this ***Appendix A***, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5 Duration of Mitigation Measures.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this ***Appendix A*** or in ***Appendix B*** to Market Rule 1.

III.A.3. Consultation Requirements

III.A.3.1. In General.

If through the application of an appropriate index or screen or other monitoring of market conditions, conduct is identified that (i) exceeds an applicable threshold, and (ii) has a material effect, as specified below, on one or more prices or NCPC payments in the New England Markets administered by the ISO, the Internal Market Monitor will take the steps set forth in this Section III.A.3:

III.A.3.1. Notice and Opportunity to Respond.

Before imposing mitigation for violation of general market thresholds (excluding thresholds regarding congestion mitigation)

(a) The Internal Market Monitor will, whenever practicable, contact the Market Participant engaging in the identified conduct to request an explanation of the conduct;

(b) If the explanation, if available, considered together with other information available to the Internal Market Monitor, indicates to the satisfaction of the Internal Market Monitor that the questioned conduct is consistent with competitive conduct as discussed above in Section III.A.2.4.2(b) no further action will be taken; and

(c) The Internal Market Monitor will consider any information a Market Participant submits, but is not required to delay mitigation while waiting for information.

III.A.3.1.2.Consideration of Information in All Cases.

In every case, the Internal Market Monitor will consider all available explanations of behavior that are based on a Market Participant's cost of providing any market product, including

(a) Any relevant opportunity costs,

(b) The need to shape bids and offers for a Limited Energy Resource to maximize the economic value from the Resource over time given the unique characteristics of the Resource, and

(c) any special price limitations applicable to dual-fuel resources.

III.A.3.1.3.Advance Consultation by Market Participant.

If a Market Participant anticipates submitting offers in a market administered by the Internal Market Monitor that will exceed the thresholds specified in Sections III.A.4, III.A.5, III.A.7, or III.A.8 for identifying conduct inconsistent with competition, the Market Participant may contact the Internal Market Monitor to provide an explanation of any legitimate basis for any such changes in the Market Participant's offers. If a Market Participant's explanation of the reasons for its bidding indicates to the satisfaction of the Internal Market Monitor that the questioned conduct is consistent with competitive conduct, no further action will be taken.

III.A.3.1.4. Market Participant Access to Its Reference Levels.

(a) The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's offers; the energy components will generally be available on a daily basis, but in all cases Reference Levels will be available upon request. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

(b) Upon request or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.5.6 for that Market Participant. If cost data or other information submitted by a Market Participant indicates to the satisfaction of the Internal Market Monitor that the

Reference Levels for that Market Participant should be changed, revised Reference Levels shall be determined, communicated to the Market Participant, and implemented, as soon as practicable.

III.A.4. Physical Withholding

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This Section defines thresholds used to identify possible instances of physical withholding. This Section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

III.A.4.2.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,

(b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,

(c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or

(d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.3. Thresholds for Identifying Physical Withholding.

III.A.4.3.1. Initial Thresholds.

Except as specified in subsection III.A.4.3.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

(a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;

(b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.3.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that is not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.3.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.3.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.4. Hourly Market Impact and NCPC Thresholds.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets or NCPC payments in excess of either of the thresholds in ***Exhibit 1***, or Section III.A.5.3.3, as appropriate.

III.A.5. Economic Withholding and Uneconomic Production

III.A.5.1. Purpose.

This Section addresses mitigation relating to economic withholding, uneconomic production and reliability commitment. If conduct is detected that exceeds one of more of the thresholds specified in Sections III.A.5.3 or III.A.5.4 and the Internal Market Monitor determines that there is a market impact to the extent required under Section III.A.5.5, the conduct shall be remedied by the prospective application of a Default Offer as described in Section III.A.5.7. If conduct is detected that fails the Commitment Offer Test in Section III.A.5.8.3 relating to reliability commitment mitigation, the conduct shall be remedied by the application of mitigation as described in Section III.A.5.8.4.

III.A.5.2. Applicability.

III.A.5.2.1. In General.

Only Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated in the Real-Time Energy Market. In the event a mitigation measure is imposed on a Supply Offer for a Resource pursuant to Section 5.8 of the ***Appendix A***, the Resource's NCPC payments shall not be mitigated under Section 5.7 for the same Operating Day.

III.A.5.2.1.1. Resources with Partial Capacity Supply Obligations.

Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding; notwithstanding the foregoing, the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of the block containing the Resource's Economic Minimum Limit and the highest block containing megawatts with a Capacity Supply Obligation;

(b) the entire offer block of a Resource shall be treated as having a Capacity Supply Obligation in any case where the block contains megawatts that are subject to a Capacity Supply Obligation;

(c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, by default the megawatts that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the megawatts that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five business days prior to the start of the month. Such a proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior; and

(d) Day-Ahead Energy Market mitigation measures will apply to all hours in the Day-Ahead Energy Market.

III.A.5.2.2. Pivotal Supplier.

A "Pivotal Supplier" shall mean, for each hour any Market Participant whose aggregate energy Supply Offers (up to and including Economic Max) for such hour are greater than the Supply Margin. The "Supply Margin" for an hour shall mean the total energy Supply Offers (up to and including Economic Max) for such hour, less total system load (as adjusted for net interchange with other Control Areas and including Operating Reserve). Prior to the Day-Ahead clearing process or the Real-Time hourly dispatch, the Internal Market Monitor shall calculate the Supply Margin and designate any Pivotal Suppliers and related generating Resources for each hour in the Day-Ahead Energy Market and the Real-Time Energy Market. In the Day-Ahead Energy Market, an ISO load forecast shall be used in making the above determination.

III.A.5.3. Thresholds for Identifying Economic Withholding.

III.A.5.3.1. General Thresholds.

The Internal Market Monitor shall investigate the reasons for and market impact of any offers from a Pivotal Supplier that exceed the following thresholds. Offers from a Pivotal Supplier exceeding these thresholds and market impact thresholds and for which no sufficient explanation has been provided, shall be mitigated to the Default Offer as determined in Section III.A.5.7.3.

(a) Energy Offer Price. A 300 % increase or an increase of $100/ MWh above the Reference Level, whichever is lower, but excluding offers under $25.

(b) Startup and No-load Offer Price. A 200 % increase above the Reference Level.

(c) Reserved.

(d) Time Based Offer Parameters. An increase greater than 2 hours in elements of a generating Resource's Offer Data that are expressed in time (e.g. minimum run time, minimum down time, cold start time, hot start time) or greater than six hours for any combination of such time-based Offer Data compared to the unit's Reference Levels.

(e) Offer Parameters Expressed Other than in Time or Dollars. A 100 % increase for Offer Data that are minimum values, or a 50 % decrease for Offer Data that are maximum values (including, but not limited to, ramp rates and maximum starts per day).

III.A.5.3.2. Reserved.

III.A.5.3.3. Additional Thresholds Applicable in Constrained Areas.

In addition to the thresholds set forth in Section III.A.5.3.1, for generating Resources located in a constrained area, the following thresholds shall be employed by the Internal Market Monitor to identify economic withholding that may warrant mitigation measures. Offers exceeding these conduct thresholds and market impact thresholds and for which no sufficient explanation has been provided, shall be mitigated to the Reference Level determined as specified in Section III.A.5.6.

(a) For Supply Offers for the Real-Time Energy Market: for intervals in which a generating Resource is dispatched for the purpose of relieving a transmission constraint above the level at which it otherwise would have been dispatched ("Constrained Hours"), the Internal Market Monitor shall assess the market impact of any Supply Offers (Section III.A.5.5.2(b)) that meet the following thresholds:

(i) Energy Offer price – an increase of $25 or 50%, whichever is lower, above the Reference Level; or

(ii) Start-up or no-load price – an increase of 25% above the Reference Level.

(b) For Supply Offers for the Day-Ahead Energy Market: for all Constrained Hours (as defined above) the Internal Market Monitor shall assess the market impact of any Supply Offers for the generating Resource that meet a threshold determined in accordance with the formula specified in subsection (a).

III.A.5.4. Threshold for Identifying Uneconomic Production.

In addition to the thresholds governing forms of economic withholding in Section III.A.5.3, the Internal Market Monitor will monitor for actions not consistent with competitive conduct, as defined in Section III.A.2.4.2(b), involving uneconomic production. The following thresholds may warrant the imposition of a mitigation measure as provided in Section III.A.5.7: (i) Energy scheduled at an LMP that is less than 20% of the applicable Reference Level and that causes transmission congestion; or (ii) Real-Time output from a Resource that exceeds 110% of the ISO's Dispatch Rate, and causes transmission congestion.

III.A.5.5. Hourly Market Impact and NCPC Thresholds

III.A.5.5.1. Initial Investigation.

Before imposing any mitigation measure as permitted in Section III.A.5.7, with regard to offers and bids identified in accordance with Sections III.A.5.3.1, III.A.5.3.3, and III.A.5.4, the Internal Market Monitor shall investigate the reasons for the change in accordance with the applicable provisions of Section III.A.3. If the offers and bids in question are not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the offers and bids in question would, if not mitigated, cause a material effect on the LMP at a Node, or clearing prices in the New England Markets or NCPC charges as provided in Sections III.A.5.5.2 and III.A.5.5.3.

III.A.5.5.2. Market Impact Thresholds.

Before a mitigation measure is imposed on offers exceeding the conduct thresholds, the Internal Market Monitor will determine whether there is an impact as follows:

(a) For offers exceeding the thresholds in Section III.A.5.3.1, a material effect is one in excess of either of the thresholds in ***Exhibit 1***, Section 1 or ***Exhibit 1***, Section 2 as applicable.

(b) For offers exceeding thresholds in Section III.A.5.3.3, a material effect is one in excess of the conduct threshold specified in Section III.A.5.3.3 above or NCPC payment thresholds as specified in ***Exhibit 1***, Section 2.

III.A.5.5.3. Calculation of Price Impact.

(a) When it has the capability to do so, the Internal Market Monitor shall determine the effect on prices in constrained areas as the difference between the LMP at the Resource node and the LMP at the Hub. When it has the capability to do so, the Internal Market Monitor shall determine the effect on prices in unconstrained areas by rerunning the ISO's market settlement software (MSS) through the market operator interface (MOI). The Internal Market Monitor shall determine the effect on NCPC payments of questioned conduct by comparing NCPC payments calculated using actual offers to NCPC payment calculated using the default offer.

(b) When a determination in accordance with paragraph (a) above is not practicable, including, but not limited to when market operations are being performed in the back-up control center during an Emergency, the Internal Market Monitor shall manually determine the effect on prices or NCPC payments of questioned conduct. The price impact analysis will be performed to allow *ex ante* mitigation in the Day-Ahead Energy Market. *Ex ante* mitigation in the Real-Time Energy Market will be performed as soon as practicable.

(c) The Internal Market Monitor may set thresholds below which it need not apply the MSS and MOI if it is reasonable to conclude that the market impact thresholds are not likely to be violated.

(d) In constrained areas, if appropriate models are not available as the result of limitations in hardware, software, or other technical difficulties, the Internal Market Monitor will manually evaluate the impact to determine if it is at least as large as the threshold value. If that is not practicable, then either of the following will be deemed to be a violation of the market impact screen for a constrained area Resource exceeding a conduct threshold specified in Section III.A.5.3: (i) the scheduling of such Resource, or (ii) if the unit is not scheduled, a determination that the Reference Level for such Resource is less than the offer price of the marginal resource by more than the threshold specified in ***Exhibit 2***, Section 2.4, will be deemed to have violated the market impact screen.

III.A.5.6. Calculation of Resource Reference Levels.

III.A.5.6.1. Methods for Determining Reference Levels.

The Internal Market Monitor will calculate a reference price or, where an element of a bid or offer is not in dollars, the time-based or quantity level (any of which being referred to as a "Reference Level") for each component of a generator's bid on the basis of the following procedures:

(a) The Internal Market Monitor will calculate Reference Levels using the first of the following three procedures for which adequate information is available, with the understanding that, for dollar-based Supply Offer parameters, Reference Levels will be calculated using the third of the three procedures if the

Reference Levels calculated using the third procedure are greater than the Reference Levels calculated using either of the first two procedures.

(i) The lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation (excluding negative values) or bid components (hereinafter, a "Submitted Offer") in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource;

(ii) If that procedure is not applicable due to lack of data, then the mean of the LMP at the Resource's location during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours or load levels, adjusted for changes in fuel prices; or

(iii) A level negotiated with the Market Participant submitting the bid or bids at issue, and intended to reflect the Resource's marginal costs, provided such a level has been negotiated prior to the occurrence of the conduct being examined by the Internal Market Monitor, and provided that the Market Participant has provided data on the Resource's operating costs in accordance with specifications provided by the Internal Market Monitor. The Internal Market Monitor's determination of a generating unit's marginal costs shall include an assessment of the unit's incremental operating costs in accordance with the following formula, and such other factors or adjustments as the Internal Market Monitor shall reasonably determine to be appropriate based on such data supplied by the Market Participant or otherwise available to the Internal Market Monitor:

(heat rate * fuel costs) + (emissions rate * emissions allowance price) + other variable and operating maintenance costs

(b) Notwithstanding Section IIIA.5.6.1(a), for any Resource that has been flagged as VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market in the previous 90 days, if the ratio of (the sum of the operating hours for flagged days during the previous 90 days in which the number of Day-Ahead and Real-Time hours operated out of economic merit order exceed the number of Day-Ahead and Real-Time hours operated in economic merit order) divided by (the total number of Day-Ahead and Real-Time operating hours during the previous 90 days) is greater than or equal to 50 percent, then the Resource is not eligible for a

Reference Level as described in subsection (i) above and will receive a Reference Level as described in subsection (iii) above. For the purposes of this subsection:

(1) A flagged day is any day in which the Resource has been flagged as VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.

(2) Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared MWs greater than zero and hours in the Real-Time Energy Market for which a Resource has metered MWs greater than zero. For days for which Real-Time Energy Market metered MWs are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered MWs values will be used.

(3) Self-Scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

(4) The determination as to whether a Resource operated in economic merit order during an hour will be based on its incremental energy offer.

III.A.5.6.2 Insufficient Data.

If sufficient data does not exist to calculate a Reference Level as provided in Section III.A.5.6.1, the Internal Market Monitor may determine a Reference Level on the basis of:

(a) the estimated costs of the generating unit, taking into account appropriate input from the Market Participant; or

(b) an appropriate average of competitive bids of one or more similar generating units.

III.A.5.7. Mitigation Measures

III.A.5.7.1. Manual Review Prior to Mitigation.

The Internal Market Monitor will manually review a generating Resource's Reference Level before imposition of mitigation where practicable.

III.A.5.7.2. Conditions for Imposition of Mitigation Measures.

The Internal Market Monitor may impose a Default Offer as set forth in this Section III.A.5.7 if the following conditions have been met:

(a) A Submitted Offer exceeds an applicable threshold set forth in Sections III.A.5.3 and III.A.5.4 for an available Resource; and the conduct is not explained to the satisfaction of the Internal Market Monitor in accordance with Section III.A.3; and

(b) The market impact thresholds described in Section III.A.5.5 are exceeded.

III.A.5.7.3. Level of Default Offers.

A substitute mitigated offer (a "Default Offer") shall be designed to cause a Market Participant to offer as if it faced workable competition during a period when (i) the Market Participant does not face workable competition, and (ii) has responded to such condition by engaging in economic withholding. In designing and implementing Default Offers, the Internal Market Monitor shall seek to avoid causing a Resource to offer below its marginal cost.

III.A.5.7.4. Implementation.

(a) The Default Offer may establish a mitigated value for one or more components of the offer for a given Resource equal to a Reference Level for that component of the Resource's offer determined as specified in Section III.A.5.6.1.

(b) A Resource subject to a Default Offer shall be paid the LMP or other market clearing price applicable to the output from the Resource. Accordingly, a Default Offer shall not limit the price that a Resource may receive or pay unless the Default Offer determines the LMP or other market clearing price applicable to that Resource.

(c) Mitigation measures shall not be applied if the price effects of the measures would cause the average day-ahead energy price in the mitigated locations or zones to rise over the entire day.

(d) Any mitigation measure imposed under this Section III.A.5.7 will be in effect for the following duration:

(i) For mitigation requiring application of the impact test in Section III.A.5.5 above, mitigation measures shall be imposed from the first hour in which the impact test is met through the end of the Operating Day, or from the first hour in which the impact test is met through the end of the mitigated Resource's minimum run time, whichever is longer.

(ii) For mitigation not requiring application of the impact test in Section III.A.5.5 above, (a) mitigation of offer parameters expressed in dollars shall be imposed from the first hour in which the applicable conduct threshold is violated through the end of the Operating Day, or from the first hour in which the applicable conduct threshold is violated through the end of the mitigated Resource's minimum run time, whichever is longer, and (b) mitigation of offer parameters expressed other than in dollars will be in effect for the entire first Operating Day and, if the minimum run time of the Resource carries over to the second Operating Day, the entire second Operating Day.

(e) The posting of the Day-Ahead schedule, rebidding period and reliability commitment run may be delayed if necessary for the completion of mitigation procedures.

(f) Mitigation that does not affect the LMP or a clearing price in another ISO market may be applied in the settlement process.

III.A.5.8. Reliability Commitment Mitigation.

III.A.5.8.1. Applicability.

The mitigation measures prescribed in this Section III.A.5.8 shall apply to Supply Offers for Resources that are committed to provide or Resources that are required to remain online to provide:

(a) outside of the Day-Ahead Energy Market, local first contingency protection or local second contingency protections;

(b) voltage support or voltage control; or

(c) Special Constraint Resource Service.

III.A.5.8.2. Duration

Any mitigation measure imposed pursuant to this Section III.A.5.8 will be in effect for the follow duration.

(a) *Resources with a Minimum Run Time Carryover*. For a Resource with a minimum run time that carries over from one Operating Day to the following Operating Day, mitigation will be in effect for the entire first Operating Day through the minimum run time of the Resource. Notwithstanding the foregoing, if the resource is selected for one of the reasons, in Section III.A.5.8.1 after the start of the Operation Day, then mitigation will be in effect from the time of such selection.

(b) *Resources without a Minimum Run Time Carryover*. For a Resource with a minimum run time that does not carry over from one Operating Day to the following Operating Day, mitigation will be in effect for the entire Operating Day, or if the decision to mitigate is made after the start of the Operating Day, then from the time at which the decision is made through the remainder of the Operating Day.

III.A.5.8.3. Commitment Offer Test

All Supply Offer parameters expressed in monetary values will be tested by application of the following formula.

(Low Load Cost at Offer – Low Load Cost at Mitigation Value)<Commitment Cost Threshold

Where,

Commitment Cost Threshold = the lower of (0.1 times Low Load Cost at Mitigation Value) or ($80 times the Resource’s Economic Maximum).

Low Load Cost = the cost of running the Resource at Economic Minimum calculated using the Following formula:

(Cold Start-Up Fee + (No Load Fee * minimum run time) + (Price of Energy at Economic Min * Economic Min* minimum run time))

Low Load Cost at Offer = Low Load Cost calculated with unmitigated dollar-based values of the Supply Offer.

Low Load Cost at Mitigation Value = Low Load Cost calculated with dollar-Based Mitigation Values of the Supply Offer.

Price of Energy at Economic Min = The price in the Supply Offer for energy at the Resource's Economic Min.

Mitigation Value = Max [Reference Level, cost-based Reference Level as determined in Section III.A.5.6.1 (b)(iii)]

If the (Low Load Cost at Offer – Low Load Cost at Mitigation Value) is equal to or greater than the Commitment Cost Threshold, a failure of the Commitment Offer Test will be deemed to have occurred.

If a Resource's combined minimum run time and minimum down time exceed 24 hours, then the Commitment Offer Test will use the greater of 24 hours or the Resource's minimum run time for the minimum run time.

III.A.5.8.4 Consequence of Failing Commitment Offer Test.

If a Resource fails the Commitment Offer Test and on the basis of its unmitigated Supply Offer would receive NCPC Credits, the mitigation values for (a) Start-Up Fee (cold, intermediate, or hot as appropriate) (b) No-Load Fee and (c) energy price shall be used for purposes of calculating NCPC Credits for the Resource in the Day-Ahead Energy Market and Real-Time Energy Market under Appendix F of this Market Rule 1.

III.A.5.9. Determination of Offer Competitiveness During Shortage Event

The Internal Market Monitor shall evaluate the competitiveness of the Supply Offer of each resource with a Capacity Supply Obligation that is off-line during a Shortage Event, as described below. The evaluation for competitiveness shall be performed on Supply Offers in the Day-Ahead Energy Market and Supply Offers made during the re-offer period. A determination of non-competitiveness for a Day-Ahead Energy Market Supply Offer or a Supply Offer made during the re-offer period which affects an hour shall constitute a finding of non-competitiveness for that hour.

(a) The thresholds used for evaluation shall be the general thresholds in Section III.A.5.3.1 unless the constrained area mitigation thresholds apply in the Day-Ahead Energy Market or Real-Time Energy Market and the resource under evaluation could have fully or partially relieved the constraint during the applicable Shortage Event. If the constrained area mitigation thresholds apply, then the energy price Supply Offer parameter and the Start-Up Fee and No-Load Fee parameters shall be evaluated for competitiveness using the thresholds in Section III.A.5.3.3.

(b) If the value of any of the following Supply Offer parameters for a resource exceeds the relevant thresholds for an hour, all MW for the resource for the hour shall be non-competitive:

(i) The Start-Up Fee and No-Load Fee;

(ii) Each time-based Supply Offer parameter;

(iii) The energy price Supply Offer parameter up to and including the Economic Minimum Limit.

(c) If none of the parameters evaluated for competitiveness pursuant to Section III.A.5.9(b) above are non-competitive for an hour, then the energy price parameter for each incremental Supply Offer block above the resource's Economic Minimum Limit shall be evaluated for competitiveness using the thresholds identified in Section III.A.5.9(a) above, in order of lowest energy price to highest energy price. If any Supply Offer block is non-competitive, then that block and all blocks above it shall be non-competitive, and all blocks below it shall be competitive.

III.A.5.10. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.6. [Reserved]

III.A.7. Demand Bids

The Internal Market Monitor will monitor Demand Resources as outlined below:

(a) LMPs in the Day-Ahead and Real-Time Energy Markets shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.

(b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.8. Mitigation of Increment Offers and Decrement Bids

III.A.8.1 Purpose.

The provisions of this Section III.A.8 specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement

Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and ISO New England Manuals.

III.A.8.2. Implementation.

III.A.8.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead and Real-Time LMPs, measured as:

$$(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.8.2.2. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead and Real-Time markets, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

(i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.

(ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.

(iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead and Real-Time Energy Markets.

III.A.8.3. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in Market Rule 1.

III.A.8.4. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.9. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.9.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

(a) Section III.13.1.1.2.6 Review by Internal Market Monitor of Offers from New Generating Capacity Resources Below 0.75 Times CONE.

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

(c) Section III.13.1.2.3.2 Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

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

(e) Section III.13.1.7. Internal Market Monitor Review of Offers and Bids.

III.A.9.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.9.3 Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.9.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Participant in accordance with Section III.A.3 of this ***Appendix A***. The Internal

Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.9.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer ***Appendix B*** in accordance with the provisions thereof.

III.A.9.6 Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.

Article 5 of the Form of Cost-of-Service Agreement in Appendix I to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.10. Request for Additional Cost Recovery.

III.A.10.1 Filing Right.

If either (a) as a result of mitigation applied to a Resource under this Appendix A for all or part of one or more Operating Days, or (b) in the absence of mitigation, despite having submitted a Supply Offer at the energy offer cap specified in Section III.1.10.1A(d) of Market Rule 1, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for those Operating Days, the Market Participant may, within **sixty** days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.

III.A.10.2 Contents of Filing.

Any Section 205 filing made pursuant to this Section III.A.10 shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource for the Operating Days exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource for the Operating Days exceeded the costs as reflected in the Supply Offer at the energy offer cap; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.10.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.10.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.10 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.10.2(i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.10 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III.A.10.

III.A.10.4 Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this Section III.A.10, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in Question.

III.A.11. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.11.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in ***Appendix D*** to Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.
- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.11.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral (as defined in ***Appendix D***) shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.12. Reporting

III.A.12.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this ***Appendix A***, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

(a) the opportunity costs associated with Demand Reduction Offers;
(b) the accuracy of Demand Response Baselines;
(c) the method used to achieve a demand reduction, and;
(d) the accuracy of reported demand levels.

III.A.12.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.12.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.12.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more State public utility commission (s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A***.

III.A.12.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISOs website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.12.3 of this ***Appendix A***.

III.A.12.3. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.12.4. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of ***Appendix A***. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

(i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.

(ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.

(iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.

(iv) Review and assessment of the effectiveness of ***Appendix A*** and the administration of ***Appendix A*** by the Internal Market Monitor for consistency and compliance with the terms of ***Appendix A.***

(v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.12.5. Other Internal Market Monitor or External Market Monitor Communications with Government Agencies.

III.A.12.5.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the

Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.12.5.2 Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;

(b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;

(c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.12.5.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.12.2.2.

III.A.12.6. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). With respect to state regulatory bodies and state attorneys general ("authorized state agencies"), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement action of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten business days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information..

III.A.13. Ethical Conduct Standards

III.A.13.1 Compliance with ISO New England Inc. Code of Conduct.
The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as ***Exhibit 5***.

III.A.13.2. Additional Ethical Conduct Standards.
The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.13.2.1. Prohibition on Employment with a Market Participant.
No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.13.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.13.3. Additional Standards Application to External Market Monitor.
In addition to the standards referenced in the remainder of this Section 13 of Appendix A, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standards(s) shall control.

III.A.14. Protocols on Referrals to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) The name(s) of and, if possible, the contact information for, the entity (ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);

(2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;

(3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

(4) The specific act(s) or conduct that allegedly constituted the Market Violation;

(5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

(6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;

(7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.15. Protocol on Referral to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) A detailed narrative describing the perceived market design flaw(s);

(2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;

(3) The rule or tariff change (s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;

(4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

SECTION III

MARKET RULE 1

APPENDIX E

~~LOAD RESPONSE PROGRAM~~DEMAND RESPONSE

APPENDIX E

~~LOAD RESPONSE PROGRAM~~DEMAND RESPONSE

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APPENDIX E

~~LOAD RESPONSE PROGRAM~~

DEMAND RESPONSE

~~III.E.1 Introduction~~

~~III.E.1.1 Goal~~~~.~~

~~The purpose of the Load Response Program ("LRP") is to facilitate load response during periods of high wholesale prices by providing appropriate incentives. Load Response Program incentives are available to any Market Participant which, consistent with the requirements set forth herein, enrolls a Load Response Program Asset in the Day-Ahead Load Response Program or in the Real-Time Price Response Program to reduce electricity consumption in the New England Control Area during periods of high wholesale prices. DRP-Only Customers must satisfy any applicable financial assurance criteria and pay an annual service fee of $500. End User Participants that participate as Governance Only Members and wish to participate in the Load Response Program must satisfy any applicable financial assurance criteria. The service fee will be applied to the ISO's expenses.~~

~~III.E.1.2 Eligibility.~~

~~The overall Load Response Program comprises the following individual components:~~

- ~~Day-Ahead Load Response Program~~
- ~~Real-Time Price Response Program These programs are further detailed in this Appendix E and the ISO New England Manuals. Generating Resources that are already qualified as generating assets are not eligible to participate in the Load Response Program; however, Market Participants with generating Resources directly connected to end-use customer load and located behind the end-use customer's billing meter may register the generating Resource as a Load Response Program Asset and Load Response Program payments associated with the generating Resource are limited to the end-use customer load served by that generating Resource which reduces the amount of energy that would otherwise have been produced by other resources on the electricity network in the New England Control Area. Real-Time Demand Response Assets must be available under the applicable provisions of Section III.13 of Market Rule 1. Market Participants with assets registered in the Real-Time Price Response Program or with~~

~~registered Real-Time Demand Response Assets have the option of participating in the Day-Ahead Load Response Program.~~

~~**III.E.1.3 Effectiveness.**~~

~~The Load Response Programs (Day-Ahead Load Response Program and Real-Time Price Response Program) will be effective through May 31, 2012.~~

~~**III.E.1.4 Allocation of Costs**.~~

~~Load Response Program costs will be allocated to Regional Network Load on a system wide basis. To the extent that a program participant's offer clears (is accepted), any charges or credits associated with such deviations will be allocated to the program participant. The balancing credit or charge will be allocated to Regional Network Load on a system wide basis.~~

~~**III.E.1.5 General Requirements**.~~

~~A Load Response Program Asset cannot span multiple Load Zones; beginning with the Capacity Commitment Period starting June 1, 2011, a Real-Time Demand Response Asset cannot span multiple Dispatch Zones. All Load Response Program Assets are required to have interval metering or an approved Measurement and Verification Plan; Market Participants with Real-Time Demand Response Assets in the Load Response Program must comply with the approved Measurement and Verification Plan for the associated Real-Time Demand Response Resource.~~

~~**III.E.1.6 Restrictions on Load Response Asset Registration:**~~

~~A Market Participant may not register and must retire if previously registered a Load Response Program Asset that is comprised of:~~

~~(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or~~

~~(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.~~

~~III.E.2. Day-Ahead Load Response Program~~

~~The Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Programs. 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.~~

~~III.E.2.1 Offer Parameters~~~~.~~

~~(a) A Market Participant may submit an offer in the Day-Ahead Load Response Program, concurrent with the Day-Ahead Energy Market, for a Load Response Program Asset in increments of 100 kW or more. Load Response Program Assets may be aggregated to reach the 100 kW minimum.~~

~~(b) The minimum offer level (expressed in $/MWh) is calculated on a monthly basis and is the Forward Reserve Fuel Index (expressed in $/MMBtu) multiplied by an effective heat rate of 11.37 MMBtu/MWh with the product rounded to the nearest dollar, and shall be specified by the ISO prior to the start of each month.~~

~~(c) The maximum offer level is $1,000/MWh.~~

~~(d) Real-Time Demand Response Assets participating in the Day-Ahead Load Response Program may be eligible to participate in the Forward Capacity Market pursuant to Section III.13 of Market Rule 1; assets participating in the Day-Ahead Load Response Program that participate in the Real-Time Price Response Program are not eligible to participate in the Forward Capacity Market.~~

~~III.E.2.2 Payment.~~

~~A Market Participant with a Load Response Program Asset that has been offered into and clears (is accepted) in the Day-Ahead Load Response Program, concurrent with the Day-Ahead Energy Market, will be paid the applicable Day-Ahead Zonal Price for all hours that the offer clears in the Day-Ahead Load Response Program, which may include hours that a Resource is dispatched under the provisions of Section III.13 of this Market Rule 1. To the extent a Market Participant's offer clears in the Day-Ahead Load Response Program and the load interruption of the participant's associated Load Response Program Asset deviates in Real-Time from its cleared offer, the Market Participant will be charged the Real-Time Locational Marginal Price for the Load Zone within which the Load Response Program Asset is located~~

~~by the amount of load response that is less than its cleared offer in the Day-Ahead Load Response Program and the Market Participant will be credited the Real-Time Locational Marginal Price for the Load Zone within which the Load Response Program Asset is located by the amount of load response that is greater than its cleared offer. The balancing credit or charge will be allocated to Regional Network Load on a system wide basis. Data for calculating actual performance, including the base line and actual reductions shall be provided on a daily basis with other meter reading data.~~

~~III.E.3. Real-Time Price Response Program~~

~~III.E.3.1 Conditions for Price Response.~~

~~Voluntary reductions will be allowed when the forecasted hourly Zonal Price produced by the Day-Ahead Energy Market or any day-ahead, or in day (based upon revised updates) resource adequacy analysis is greater than or equal to $100/MWh and the ISO has transmitted instructions that the eligibility period is open. Real-Time telemetering is not required, but interval metering or an approved Measurement and Verification Plan is required.~~

~~III.E.3.2 Payment.~~

~~Market Participants with assets participating in the Real-Time Price Response Program will receive the higher of the applicable Real-Time Zonal Price for interrupted consumption (measured against the base line) or a minimum payment of $100/MWh when the eligibility period is opened. Assets registered in the Real-Time Price Response Program are not eligible to qualify as a Demand Resource under the Forward Capacity Market.~~

~~III.E.3.3 Communication That Eligibility Period Is Opened.~~

~~Communications that an eligibility period is open are made through e-mail notification and a posting on the ISO's web site.~~

~~III.E.3.4 Data Reporting.~~

~~III.E.3.4.1 Daily Reporting.~~

~~The interval meter readings are submitted daily to the ISO on the same schedule as other meter data.~~

~~III.E.3.4.2 "Super" Low Tech.~~

~~Under this reporting option the interval meter is not read daily nor is the meter reading supplied to the ISO within the following 36 hours. Market Participants are paid when the Real-Time Energy Market is re-settled pursuant to Section III.3 of Market Rule 1. Market Participants in this option waive their ability to request resettlement with respect to billing for these Load Response Program Assets.~~

~~III.E.4. Metering and Settlement~~

~~Additional details concerning metering requirements and settlement procedures along with calculation of baseline quantities to be used to calculate the amount of interruption actually obtained are contained within the ISO New England Manuals.~~

~~III.E.5. Demand Response Reserve Pilot Program~~

~~III.E.5.1 Demand Response Reserve Pilot Program Objectives.~~

~~The objectives of the Demand Response Reserve ("DRR") Pilot program are: (1) to demonstrate based on actual response data whether Demand Resources and Settlement Only Resources (collectively referred to in this Section III.E.5 as "DR Resources") can reliably provide reserve services, specifically 10-minute and 30-minute Operating Reserve services; (2) to determine the requirements for the level and type of control room communications, dispatch, metering, and telemetry sufficient for DR Resources providing reserve services; and (3) to identify, evaluate, and deploy lower cost communications and telemetry solutions that meet the requirements to provide reserve services.~~

~~III.E.5.2 DRR Pilot Program Description.~~

~~III.E.5.2.1 DRR Pilot Program Duration.~~

~~The DRR Pilot program will continue through May 31, 2010. Applications by Market Participants, with a valid DRR Pilot Training Certificate number, to participate in the Winter 2008/2009 Forward Reserve Procurement Period are due August 23, 2008, and for future Forward Reserve Procurement Periods will be submitted concurrent with the bidding window for the Forward Reserve Procurement Period. During the course of the DRR Pilot program, the ISO may modify the program selection and availability criteria to take into account the actual performance of different DR Resource categories. The ISO will report at least annually to the Markets Committee on the status of the DRR Pilot program.~~

~~III.E.5.2.2 DRR Pilot Program Size and DR Resource Enrollment.~~

~~A total of up to 50 MW from the Connecticut Load Zone will be enrolled in the DRR Pilot program from the following categories of DR Resources:~~

~~(i) customers with Distributed Generation or Settlement Only Resources;~~
~~(ii) customers with Distributed Generation and weather-dependent load;~~
~~(iii) weather-independent load reduction Resources; and~~
~~(iv) weather-dependent load reduction Resources. DR Resources will be selected in accordance with Section III.E.5.2.3 so as to represent the population of DR Resources that would likely participate in a competitive reserve services market.~~

~~Resources that are 5 MW or larger may be eligible to participate in the DRR Pilot program, subject to approval by the ISO. DR Resources may be aggregated provided the aggregated DR Resources must be located at a single Node within the New England Control Area and must comply with the measurement and verification requirements applicable to DR Resources as specified in the ISO New England Manuals. Once DR Resources have been integrated into reserve markets, however, aggregation of DR Resources participating in the reserve markets will be governed by the applicable reserve market requirements.~~

~~The DRR Pilot program will not affect the quantity or the applicable 10-Minute or 30Minute Forward Reserve Clearing Prices for Resources acquired through the Forward Reserve Auction. A DR Resource may not simultaneously participate in the DRR Pilot program and the Forward Reserve Auction.~~

~~**III.E.5.2.3 Selection Process**.~~
~~Separate DR Resource selections will be conducted for the winter and summer seasons consistent with the Forward Reserve Service Periods.~~

~~The selection process for the DRR Pilot program will consist of the following steps: (1) the DRR Pilot program will be noticed through an email transmitted to Market Participants with a valid DRR Pilot Training Certificate number when the DRR Pilot program request to participate forms are available and the period for the submission of completed forms has begun; (2) Enrolling Participants will be permitted to offer DR Resources to the ISO for consideration to be permitted to participate in the DRR Pilot program concurrent with the Forward Reserve Auction Offers; and (3) the ISO will select DR Resources so that the amount of load reduction capacity reflects the load reduction goals for each category of DR Resource listed in Section III.E.5.2.2. In the event that participation in the DRR Pilot program exceeds~~

~~the limits defined for a category of DR Resources, the ISO will conduct a random drawing by DR Resource category to determine the final participants for the period. If a DR Resource category is not fully subscribed for the period, then the ISO will have the option of selecting other DR Resources that were not initially selected to participate in the DRR Pilot program. Once a DR Resource is selected and the Enrolling Participant agrees to participate, there will be no substitution of DR Resources during that Forward Reserve Service Period. The ISO can vary the asset selection process as necessary in order to produce unbiased, statistically meaningful results, and will maintain sole discretion over the selection of assets to participate in the DRR Pilot program.~~

~~An Enrolling Participant will be given an opportunity to opt selected DR Resources out of the DRR Pilot program should it deem the payments to participating DR Resources (described in Section III.E.5.3) to be insufficient. Any DR Resource that is selected to participate in the DRR Pilot program and that does not opt out after being given an opportunity to do so will be eligible for DRR Availability Payments and DRR Performance Payments and will be subject to DRR Replacement Energy Cost Penalties (described in Section III.E.5.4).~~

~~III.E.5.2.4 Availability.~~

~~DR Resources participating in the DRR Pilot program must be available for dispatch between 7 a.m. and 11 p.m. during non-holiday weekdays, must meet the availability requirements of the Real-Time 30-Minute Demand Response Program, and must make the DRR Contract Amount (defined in Section III.E.5.3.1) available for dispatch as described in Section III.E.5.2.5. In addition, for research purposes, the ISO may investigate certain subsets of hours surrounding seasonal daily peak hours. In connection with any such investigation, the ISO may request that a certain category of DR Resource make itself available to respond to ISO dispatch instructions during such conditions. Any change to availability requirements will be made in consultation with the Enrolling Participants, and sufficient notice will be provided to participating DR Resources before any such change, and can include a request to test new communication protocols during the DRR Pilot program.~~

~~III.E.5.2.5 Dispatch.~~

~~DR Resources participating in the DRR Pilot program will be dispatched in order to restore or maintain first contingency protection ("DRR Reportable Events"). In addition, the ISO may dispatch DR Resources at additional times if DRR Reportable Events do not provide sufficient data for the ISO to evaluate DR~~

~~Resources across all pre-defined test conditions, including dispatch frequency, duration of load reduction, and season.~~

~~Except as provided below, the random activations by the ISO to gather performance data and any DRR reportable event activations of the DRR Pilot program shall not exceed 25 times and shall not exceed 50 hours in a Forward Reserve Delivery Period. If total activations approach the cap of 25 times or 50 hours, the ISO will notify participating DR Resources that if the cap is reached, the ISO will permit participating DR Resources to opt out of the DRR Pilot program. DR Resources that exercise this opt-out right will no longer be eligible to receive DRR Availability Payments and DRR Performance Payments or subject to DRR Replacement Energy Cost Penalties and will no longer be required to respond to ISO dispatch instructions in response to DRR Reportable Events pursuant to the DRR Pilot program. Those not exercising this opt-out provision will continue to be obligated to respond to ISO dispatch instructions in response to DRR Reportable Events through the end of the then current Forward Reserve Service Period; such resources will continue to receive DRR Availability Payments and DRR Performance Payments, and will be subject to DRR Replacement Energy Cost Penalties. The ISO will continue to study the performance of DR Resources that choose to not exercise the opt-out provision.~~

~~III.E.5.2.6 Metering & Communication.~~

~~The DRR Pilot program will use the existing Internet Based Communication System for activation of the participating DR Resources. Telemetry data, which is automatically transmitted from each DR Resource through their IBCS provider to the IBCS open solution every five minutes, will be transmitted by the IBCS open solution to the ISO. A separate sub-project will identify and evaluate the lower-cost, two-way communication alternatives to the current combination of Supervisory Control and Data Acquisition ("SCADA") and Remote Intelligent Gateway ("RIG") technology that is presently required to connect dispatchable Resources to the ISO. This sub-project will evaluate the use of the lower-cost dispatch and telemetering for use by DR Resources that are less than 5 MW in size. To support this evaluation, the ISO may use, in consultation with participating Enrolling Participants, alternative dispatch and telemetering solutions during the course of the DRR Pilot program. Alternative dispatch and telemetry solutions may require the transmission of telemetry data to the ISO more frequently than every five minutes. The ISO will report to the Markets Committee regarding any implementation of alternative dispatch and telemetry solutions on a semi-annual basis.~~

~~III.E.5.3 Payments To Participating DR Resources.~~

~~Enrolling Participants whose DR Resources participate in the DRR Pilot program will be eligible to receive a DRR Availability Payment, based on the applicable 30-Minute hourly Forward Reserve Payment Rate for the Connecticut Load Zone, and a DRR Performance Payment. Such payments are intended to compensate DR Resources for the additional obligations and risks associated with participation in the DRR Pilot program.~~

~~III.E.5.3.1 DRR Availability Payment.~~

~~Participating DR Resources will receive a DRR Availability Payment based upon the applicable 30-Minute Hourly Forward Reserve Clearing Price for the Connecticut Load Zone. At the beginning of each Forward Reserve Service Period, DRR Availability Payments for participating DR Resources will be based on the amount that the Enrolling Participant agrees to provide within 30 minutes when called upon by the ISO ("DRR Contract Amount"). Each time a dispatch event occurs, the DRR Availability Payment from the event start time going forward will be based on the lower of the DRR Contract Amount or the actual performance of the DR Resource. The DRR Availability Payment between the last dispatch event and the end of the Forward Reserve Service Period will be based on the actual performance of the DR Resource in the last dispatch event, not to exceed the DRR Contract Amount.~~

~~Specifically, DRR Availability Payments to a DR Resource for each hour that the DR Resource is required to be available for dispatch will equal:~~

> ~~(the 30-Minute hourly Forward Reserve Payment Rate for the Connecticut Load Zone) multiplied by (the lower of the DRR Contract Amount or the actual performance of the DR Resource).~~

~~III.E.5.3.2 DRR Performance Payment.~~

~~The DRR Performance Payment will be calculated as the product of the Amount Interrupted and the higher of the applicable Forward Reserve Threshold Price or the Real-Time Connecticut Zonal Price. For hours in which both a DRR Pilot program dispatch event and a Real-Time 30-Minute Demand Response Program event occur, DRR Pilot program participants will receive no DRR Performance Payment. At such times, DRR Pilot program participants will receive Real-Time hourly payments associated with the Real-Time 30-Minute Demand Response Program; provided, however that DRR Pilot program participants will still be subject to DRR Replacement Energy Cost Penalties as described in Section III.E.5.4.~~

~~**III.E.5.3.3 Performance Measurement.**~~

~~DR Resource performance will be determined in the same manner as in the existing Real-Time 30-Minute Demand Response Program as described in the ISO New England Load Response Program Manual, provided, however, that the customer baseline adjustment for the DRR Pilot program will be increased or decreased to reflect actual metered consumption during the two hours prior to the dispatch of the Demand Resources (i.e., adjusted symmetrically).~~

~~**III.E.5.4 Performance Penalties**~~

~~**III.E.5.4.1 DRR Replacement Energy Cost Penalty**.~~

~~The DR Resources participating in the DRR Pilot program will not be subject to a failure to reserve penalty, since such DR Resources will not be bidding into the Day-Ahead or Real-Time Energy Markets, nor will they be dispatched based upon a price. However, the formula in Section III.E.5.3.1 will decrease the DRR Availability Payment by the portion of the DRR Contract Amount not provided.~~

~~DR Resources participating in the DRR Pilot program will be required to pay a failure to activate reserve penalty based on replacement energy costs ("DRR Replacement Energy Cost Penalty"), as defined below, when they provide less than the DRR Contract Amount in response to ISO dispatch instructions. Standard Load Response Program curtailment measurement (including a symmetrically adjusted customer baseline for the two hours prior to the event as described in Section III.E.5.3.3 above) is utilized to determine performance of DR Resources including any undelivered response. The Real-Time Zonal Price used in the formula shall be the hourly Connecticut Real-Time Zonal Price.~~

> ~~DRR Replacement Energy Cost Penalty = (DRR Contract Amount – Amount Interrupted) multiplied by (Real-Time Connecticut Zonal Price).~~

~~**III.E.5.5 Enrollment and ICAP Credit**~~

~~**III.E.5.5.1 Enrollment.**~~

~~DR Resources participating in the DRR Pilot program must be registered in the Real-Time 30-Minute Demand Response Program. DR Resources participating in the DRR Pilot program shall only respond to DRR Pilot program dispatch instructions.~~

~~Settlement Only Resources participating in the DRR Pilot program must change their registration with the ISO to participate in the Real-Time 30-Minute Demand Response Program. Any Settlement Only Resource that elects to participate in the DRR Pilot program will be afforded the option at the end of the DRR Pilot program to return to "settlement only" status or to continue to participate in the Real-Time 30-Minute Demand Response Program.~~

~~**III.E.5.5.2 ICAP Credit.**~~

~~DRR Pilot program participants will receive ICAP credit pursuant to the provisions of the Real-Time 30-Minute Demand Response Program. ICAP credit will be based on DR Resource performance in response to Real-Time 30-Minute Demand Response Program events only. No additional ICAP credit will be afforded a DR Resource for participation in the DRR Pilot program. To the extent that payments associated with the Forward Reserve Auction are modified in the future, DRR Availability Payments and ICAP credits for DR Resources participating in the DRR Pilot program will also be modified in a consistent manner.~~

~~**III.E.5.6 Program Cost Allocation.**~~

~~There are two separately calculated charges for the DRR Pilot program: (1) payments associated with the DRR Availability Payment, and (2) payments associated with the DRR Performance Payment (net of DRR Replacement Energy Cost Penalties) when loads are called upon to interrupt.~~

~~**III.E.5.6.1 DRR Availability Payment Allocation.**~~

~~The charge for the DRR Availability Payments will be allocated on a pro-rata basis based on each Market Participant's share of the aggregate charges under Schedules 1, 2, and 3 of Section IV.A (Recovery of ISO Administrative Expenses) of the ISO New England Transmission, Markets and Services Tariff.~~

~~**III.E.5.6.2 DRR Performance Payment Allocation.**~~

~~The charge for the DRR Performance Payment associated with the actual interruption (net of DRR Replacement Energy Cost Penalties) will be allocated to Real-Time Load Obligation Deviation in the Connecticut Load Zone.~~

1. Demand Response Registration

A Market Participant may register a Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis to provide demand reductions during hours ending 0800 through 1800 on non-Demand Response Holiday weekdays subject to the following conditions:

(a) the asset is able to produce at least 100 kW of demand reduction, and;

(b) the metering and communication equipment associated with the asset meets the requirements specified in Section III.E.2.

1.1 Registration Parameters

During the registration process, Market Participants must submit the following information for each Real-Time Demand Response Asset:

(a) Maximum Interruptible Capacity;

(b) Maximum Load, and;

(c) Maximum Generation, for Real-Time Demand Response Assets that are comprised of Distributed Generation.

1.2 Restrictions on Real-Time Demand Response Asset Registration

A Market Participant may not register and must retire if previously registered a Real-Time Demand Response Asset that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

A Market Participant may not register an existing Generator Asset as a Real-Time Demand Response Asset for the purpose of submitting Demand Reduction Offers.

2. Metering and Communication

2.1 Interval Metering and Telemetry Requirements

The actual metered demand of each individual end-use customer facility that comprises a Real-Time Demand Response Asset must be measured using interval meters located at the individual end-use customer's retail delivery point and shall be reported to the ISO at an interval of five minutes. Actual metered demand submitted to the ISO shall not include average avoided peak distribution losses. Each generator located behind an individual end-use customer's retail delivery point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.

Interval meters required pursuant to Section III.E.2.1 must meet the following requirements:

(a) the interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes or less;

(b) if the interval meter is the same meter used by the distribution company for billing purposes, the meter is a revenue-quality meter that is accurate within ± 0.5%, and;

(c) if the interval meter is not the same meter used by the distribution company for billing purposes, the interval meter is either a revenue-quality meter that is accurate within ± 0.5% or a non-revenue-quality meter with an overall accuracy of ± 2.0%. For each non-revenue-quality meter used, the Market Participant must, during the registration process, submit certification from the meter manufacturer that the interval meter being used meets the ± 2.0% accuracy threshold, and shall specify accuracy for the following parameters:

i. current measurement;

ii. voltage measurement;

iii. A/D conversion, and;

iv. calibration.

2.2 Meter Testing

All interval meters must be periodically tested and calibrated.

Market Participants must conduct periodic meter data validation checks.

Market Participants must repair or replace meters that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters and meter data communication systems.

2.3 Auditing

The ISO may, for a Real-Time Demand Response Asset, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and measurement equipment, and witness the demand reduction activities of any facility associated with the asset.

Market Participants must make retail billing meter data from the Host Participant for the facilities associated with a Real-Time Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing, and certifying the metering, data recording and measurement equipment of Real-Time Demand Response Assets.

2.4 Communication/Telemetry

Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facilities comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area.

For Real-Time Demand Response Assets whose demand reductions are not achieved by Distributed Generation but where there is a generator located behind the retail delivery point, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of all generation.

For Real-Time Demand Response Assets whose demand reductions are achieved by Distributed Generation, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of Distributed Generation associated with the Real-Time Demand Response Asset.

3. Demand Reduction Offers

3.1 Required Demand Reduction Offer Parameters

Market Participants must submit a Demand Reduction Offer for each Real-Time Demand Response Asset that meets the requirements of this section in order to be eligible for a demand reduction payment.

A Demand Reduction Offer must be equal to or greater than the Demand Reduction Threshold Price in effect on the day the Demand Reduction Offer is made.

Demand Reduction Offers reflect the amount of demand reduction offered at the retail delivery point excluding transmission and distribution losses.

A Demand Reduction Offer shall consist of a single offer price in $/MWh (less than or equal to $1000/MWh) and a single demand reduction amount (in MW to the nearest 0.1 MW) that shall apply to hours ending 0800 through 1800 in the Operating Day.

A Market Participant may submit a single Demand Reduction Offer for each of its Real-Time Demand Response Assets for each Operating Day that is a non-Demand Response Holiday weekday.

Demand Reduction Offers for the following Operating Day must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the Operating Day and may not be changed thereafter.

The minimum Demand Reduction Offer amount for each Real-Time Demand Response Asset is 100 kW.

The maximum Demand Reduction Offer amount for each Real-Time Demand Response Asset cannot exceed the asset's Maximum Interruptible Capacity.

3.2 Optional Demand Reduction Offer Parameters

A Demand Reduction Offer may specify a minimum interruption duration of one to four hours. If a Market Participant does not specify a minimum interruption duration in its Demand Reduction Offer, the minimum interruption duration shall be one hour.

A Demand Reduction Offer may specify a curtailment initiation price (in $ per interruption). If a Market Participant does not specify a curtailment initiation price, the curtailment initiation price shall be $0.

A Demand Reduction Offer must meet the following minimum and maximum price requirements:

(a) The offer price not including the curtailment initiation price shall be greater than or equal to the Demand Reduction Threshold Price; and

(b) The offer cost of the Demand Reduction Offer, which shall include the curtailment initiation price, shall be less than or equal to $1000/MWh. The offer cost shall be computed as follows: offer cost = offer price + [curtailment initiation price/(minimum interruption duration x bid amount (MW))].

4. Day-Ahead Clearing, Scheduling and Notification

Demand Reduction Offers are cleared after the Day-Ahead Energy Market results are determined. Demand Reduction Offers are cleared by comparing the Demand Reduction Offer to the hourly Day-Ahead LMPs for the Load Zone in which the Real-Time Demand Response Asset is located. A Demand Reduction Offer associated with a Real-Time Demand Response Asset will clear in one or more hours of the Operating Day if the sum of the hourly Day-Ahead LMP times the Demand Reduction Offer amount in the cleared hours of the Operating Day is greater than or equal to the sum of the curtailment initiation price for the Operating Day and the sum of the Demand Reduction Offer price times the Demand Reduction Offer amount in the cleared hours of the Operating Day.

The ISO will provide Market Participants with demand curtailment schedules for Real-Time Demand Response Assets based on cleared Demand Reduction Offers.

The demand curtailment schedule shall reflect demand reductions (MW) at the Real-Time Demand Response Asset's retail delivery point.

5. Real-Time Scheduling of Demand Reductions

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for the next Operating Day pursuant to Section III.E.4. If a Market Participant's Demand Reduction Offer is not cleared Day-Ahead to reduce demand in an hourly time interval for the next Operating Day, the Market Participant may initiate a Real-Time demand reduction by reducing demand when the offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which a Real-Time Demand Response Asset is located.

A Market Participant will not receive a Dispatch Instruction in Real-Time for a Real-Time Demand Response Asset.

5.1 Requirements for Demand Reductions of 5 MW and Above

A Market Participant with a Real-Time Demand Response Asset that has submitted a Demand Reduction Offer for the Operating Day, must request permission from the ISO prior to reducing demand in an amount greater than or equal to 5 MW during a 60 minute period, unless the asset was dispatched or audited pursuant to Section III.13. Permission must be requested not less than 15 minutes and not greater than 60 minutes before the start of the demand reduction. The ISO may approve or deny the requested interruption based on the impact of the interruption on system reliability.

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data for the same month of the previous year. The ISO may adjust the offer data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

i. Each generator and import offer block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

ii. An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer block.

iii. A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

iv. A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from demand response exceeds the cost to load associated with compensating demand response.

v. The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} \times \frac{FPI_c}{FPI_h}$$

where FPI_h is the Forward Reserve Fuel Index for the same month of the previous year, and FPI_c is the Forward Reserve Fuel Index for the current month.

The ISO will post the resulting Demand Reduction Threshold Price on its website in advance of the Demand Reduction Threshold Price's effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Real-Time Demand Response Assets located anywhere within the New England Control Area.

7. Demand Response Baselines

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8 prior to submitting a Demand Reduction Offer for a Real-Time Demand Response Asset.

A Market Participant shall take no actions to establish a Demand Response Baseline or affect a Demand Response Baseline adjustment that results in a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers absent demand reduction payments.

For Real-Time Demand Response Assets comprised of Distributed Generation, a Market Participant shall take no actions to establish a Demand Response Baseline that results in a Demand Response Baseline that reduces the expected output levels of its generation absent demand reduction payments.

8. Real-Time Demand Reduction Obligations

8.1 Real-Time Demand Reduction of Assets Without Generation

The Real-Time demand reduction amount of a Real-Time Demand Response Asset is equal to the difference between its Demand Response Baseline adjusted pursuant to Section III.8.4 and the asset's Real-Time metered demand, during the intervals that the Real-Time Demand Response Asset was scheduled Day-Ahead by the ISO to reduce demand or was otherwise eligible to receive payment for a demand reduction in Real-Time. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered demand is greater than its adjusted Demand Response Baseline.

8.2 Real-Time Demand Reduction of Assets With Generation

To the extent a generator is located behind the retail delivery point of an individual end-use customer facility that comprises a Real-Time Demand Response Asset, the metered output of the generator in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline. The Real-Time demand reduction amount achieved by the individual end-use customer facility that comprises a Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval minus the sum of the metered demand measured at the retail delivery point and the output of all of the generators located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of all of the generators is greater than its adjusted Demand Response Baseline.

If a Real-Time Demand Response Asset is comprised of a Distributed Generation asset located behind the retail delivery point of an individual end-use customer facility, the interval metered output of the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be used to determine its Demand Response Baseline. The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be equal to the asset's incremental output in each five-minute interval relative to its Demand Response Baseline in the same intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered output is less than its Demand Response Baseline.

8.3 Treatment of Net Supply

If the metered amount measured at the retail delivery point reflects net energy supply during intervals in which Real-Time Demand Response Assets and/or Real-Time Emergency Generation Assets behind the retail delivery point had positive Real-Time demand reductions, then the amount of net energy supplied in an interval with a positive Real-Time demand reduction shall be subtracted from the Real-Time demand reduction amount in the same interval of each Real-Time Demand Response Asset and/or Real-Time Emergency Generation Asset behind that retail delivery point on a *pro rata* basis. The adjustment for net energy supply shall not result in a negative Real-Time demand reduction amount.

8.4 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Real-Time Demand Response Asset is equal to its Real-Time demand reduction amount adjusted for net supply (limited to 200% of the associated Demand Reduction Offer amount) multiplied by one plus the percent average avoided peak distribution losses.

9. Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Real-Time Demand Response Asset will be paid for its Day-Ahead Demand – Reduction Obligation multiplied by the Day-Ahead LMP for the Load Zone within which the Real-Time Demand Response Asset is located.

9.2 Real-Time Settlement

9.2.1. Real-Time Demand Response Assets with Cleared Demand Reduction Offers

A Market Participant with a Real-Time Demand Response Asset will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the final hourly Real-Time LMP for the Load Zone within which the Real-Time Demand Response Asset is located. The payment for the amount by which the Real-Time Demand Reduction Obligation exceeds the Day-Ahead Demand Reduction Obligation in an hour shall be set to zero if the provisional Real-Time LMP for that hour is less than the Demand Reduction Threshold Price.

A Market Participant will not be charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E.5.1.

9.2.2. Real-Time Demand Response Assets without Cleared Demand Reduction Offers

If the Demand Reduction Offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which the Real-Time Demand Response Asset is located, the Market Participant will be paid the final hourly Real-Time LMP multiplied by its Real-Time Demand Reduction Obligation.

A Market Participant will not be charged pursuant to Section III.E.9.2.2 if:

(a) a Demand Reduction Offer does not clear Day-Ahead pursuant to Section III.E.4, and;

(b) the Real-Time Demand Response Asset produces a negative Real-Time demand reduction amount.

A Market Participant will not be paid for a Real-Time Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E.5.1.

9.3 Cost Allocation

Payments and charges pursuant to this section will be allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes or incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

10. Average Distribution Losses

For purposes of Section III.E, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

ATTACHMENT D

ISO New England Information Policy

Table of Contents

Introduction

The ISO New England Information Policy establishes rules and guidelines regarding the appropriate disclosure of all information received, created and distributed in connection with the operation of and participation in the markets administered by ISO New England Inc. (the “ISO”). The Policy allows stakeholder committees, task forces and working groups (collectively, “Stakeholder Committees”), the ISO, and Governance Participants to share information with the benefit of a common understanding regarding how that information will be used and how appropriate confidentiality will be maintained. This Policy document consists of three sections. Section 1 highlights the Policy's intent and objectives. Section 2 discusses confidentiality issues. Finally, Section 3 specifies what types of information are available to whom. This Section, in its entirety, is intended to replace the Information Classification Document appendix of the formerly adopted Policy (March 5, 1999 version).

Changes to the Information Policy will be made in accordance with Section 11.3 of the Participants Agreement.

Section 1 -Policy Intent & Objectives

The intent of this Policy is twofold. First, to allow Governance Participants to provide certain *Confidential Information* to the ISO, Stakeholder Committees, and other Governance Participants with the benefit of a common understanding regarding how that information will be used and how appropriate confidentiality will be maintained. Second, to provide the ISO, Stakeholder Committees and Governance Participants clear guidance regarding the appropriate disclosure of all information received, created or distributed in connection with the operation of and participation in the markets administered by the ISO. This Policy will pertain to all information held by Stakeholder Committees or the ISO, or furnished by or to a Governance Participant as a result of its participation in the markets administered by the ISO, whether it is publicly available or strictly confidential.

In order to meet the general obligations of the Transmission, Markets and Services Tariff, the Participants Agreement, the Transmission Operating Agreement, the Rates Design and Funds Disbursement Agreement, and other documents that affect the rates, terms, and conditions of service, including all exhibits and attachments to the listed documents (hereafter collectively referred to as the “Filed Documents”), each Governance Participant is required to furnish to and may be entitled to receive from Stakeholder Committees or the ISO certain information, some of which may be considered confidential, commercially sensitive, and/or strategic in nature. This information is used by the ISO, Stakeholder Committees or Governance Participants, as appropriate, for the following purposes, among others:

1. To operate the bulk power supply system on a day-to-day basis.

2. To administer the Open Access Transmission Tariff.

3. To administer the New England electricity markets, including the bidding process, billing system and settlement function.

4. To monitor the competitiveness and efficiency of the market and Governance Participants' compliance with relevant market rules and procedures.

5. To assess and plan for the long term reliability and adequacy of the New England bulk power supply system.

6. To provide reports and data as required or appropriate to the various user groups as described in Section 3 of this document.

It is recognized that the successful operation of the New England Control Area is highly dependent on access to certain types of information. The high degree of bulk power supply reliability and adequacy that customers of Governance Participants have become accustomed to expect is, to some degree, a result of Governance Participants' willingness to provide the necessary information. It is only with the ISO's continued access to the information necessary to perform its duties described above that the benefits obtained from bulk power supply pooling can continue.

This Information Policy will:

1. Recognize that protecting the confidentiality of certain information is important to the Governance Participants.

2. Recognize that the ISO and each Governance Participant have the responsibility to protect the confidentiality of such information.

3. Provide procedures and guidelines to the ISO, Stakeholder Committees and Governance Participants regarding the handling, publication and distribution of all information.

This Information Policy is intended to comport with the obligation of the ISO, Stakeholder Committees and the Governance Participants to comply fully with the antitrust laws and the information access and disclosure provisions of the standards of conduct promulgated by the Federal Energy Regulatory Commission in 18 C.F.R. § 37.4 (the "Codes of Conduct"). The Information Policy is expressly intended both: **(1)** to protect against the disclosure of *Confidential Information* that could facilitate anticompetitive conduct prohibited by the antitrust laws and **(2)** to distribute information to the extent and in a manner consistent with preserving the competitiveness and efficiency of the New England electric markets and the reliability of the bulk power system.

No modifications or additions shall be made to Section 3 of this document that result in limiting the disclosure of *Confidential Information* by Governance Participants that are municipalities, state or municipal agencies, or other public agencies unless such information contains trade secrets or commercial or financial information that has otherwise been kept confidential.

Section 2 -Confidentiality Issues

2.0 Confidentiality

Confidential Information furnished by a Governance Participant to Stakeholder Committees and/or the ISO shall, for the purposes of this Information Policy, be considered the sole and exclusive property of such Governance Participant (the "Furnishing Governance Participant"). To the extent that such *Confidential Information* is furnished to Stakeholder Committees and/or the ISO it shall be used solely to perform their obligations under the NEPOOL Agreement and the ISO Agreement. No Governance Participant shall be entitled to receive from the ISO and/or Stakeholder Committees any *Confidential Information* furnished by another Governance Participant under the NEPOOL Agreement unless the Furnishing Governance Participant has provided the relevant Stakeholder Committees and/or the ISO written authorization for such release. The disclosure of *Confidential Information* in accordance with this Information Policy shall not be used by any Governance Participant as a basis for a claim that the Governance Participant furnishing such *Confidential Information* has waived, relinquished, or reduced in any way the Furnishing Governance Participant's rights to prevent further disclosure of such *Confidential Information*.

The Governance Participants recognize that one of the purposes of the ISO is to prepare analyses, forecasts and reports for the general public, reliability councils, regulators and other user groups.

Preparation of such analyses, forecasts and reports requires the use of Governance Participants' information, some of which may be *Confidential Information* of an individual Governance Participant.

Governance Participants' obligations to provide information to the ISO or Stakeholder Committees arise under the Filed Documents. Nothing in this Information Policy is intended to expand or alter those obligations. Nothing in this Information Policy requires the ISO to release information to Stakeholder Committees, Governance Participants or any other person if the ISO in good faith believes that the release of such information would violate any applicable law or regulation, including the Codes of Conduct, or the terms of any valid confidentiality agreement or have a material adverse effect on the competitiveness or efficiency of the markets administered by the ISO.

2.1 Confidential Information

The following information will be considered *Confidential Information* for the purposes of this Policy:

(a) Information that **(i)** is furnished by a Governance Participant (the "Furnishing Governance Participant") to the ISO, Stakeholder Committees or another Governance Participant, **(ii)** constitutes trade secrets or commercial or financial information, the disclosure of which would harm the Furnishing Governance Participant or prejudice the position of that Governance Participant in the New England electricity markets, and **(iii)** has been designated in writing by the Furnishing Governance Participant as confidential or proprietary either in the document which provided such information, in the transmittal materials accompanying such information, or in a separate document which identifies the information with sufficient specificity and clarity so that the entity receiving such information has been made aware that the Furnishing Governance Participant seeks confidential treatment for such information.

(b) Information that **(i)** is furnished by the ISO to a Governance Participant or a Stakeholder Committee, **(ii)** constitutes trade secrets or commercial or financial information the disclosure of which would have an adverse effect on the ability of the ISO to perform its responsibilities under the ISO Agreement, and **(iii)** has been designated in writing by the ISO as confidential or proprietary either in the document which provided such information, in transmittal materials accompanying such information, or in a separate document which identifies the information with sufficient specificity and clarity so that the entity receiving such information has been made aware that the ISO seeks confidential treatment for such information. In addition, information that is furnished by the ISO to a Governance Participant or a Stakeholder Committee relating to the job status or performance or terms of employment of any ISO employee ("ISO Employment Information") shall be *Confidential Information*.

(c) Information that **(i)** is furnished by a non-Governance Participant that takes part in a demand response program operated by the ISO (a "DR Information Provider") to the ISO, Stakeholder Committees or any Governance Participant in connection with the demand response program, **(ii)** constitutes trade secrets or commercial or financial information, the disclosure of which would harm the DR Information Provider or prejudice the position of the DR Information Provider in the demand response program, and **(iii)** has been designated in writing by the DR Information Provider as confidential or proprietary either in the document which provided such information, in the transmittal materials accompanying such information, or in a separate document that identifies the information with sufficient specificity and clarity so that the entity receiving such information has been made aware that the DR Information Provider seeks confidential treatment for such information.

(d) Information that **(i)** is furnished by a non-Governance Participant acting as a Project Sponsor to the ISO, Stakeholder Committees or any Governance Participant in connection with the Forward Capacity Market, **(ii)** constitutes trade secrets or commercial or financial information, the disclosure of which would harm the Project Sponsor or prejudice the position of the Project Sponsor in the Forward Capacity Market, and **(iii)** has been designated in writing by the Project Sponsor as confidential or proprietary either in the document which provided such information, in the transmittal materials accompanying such information, or in a separate document that identifies the information with sufficient specificity and clarity so that the entity receiving such information has been made aware that the Project Sponsor seeks confidential treatment for such information.

(e) Information disclosed to satisfy the "Minimum Criteria for Market Participation" set forth in Section II.A of the ISO New England Financial Assurance Policy that (i) is furnished by a Furnishing Governance Participant to the ISO, Stakeholder Committees or another Governance Participant or is furnished by the ISO to a Governance Participant or a Stakeholder Committee, (ii) constitutes sensitive or non-public information concerning the Participant or identifying or concerning the Principals of a Participant, the disclosure of which could harm the Furnishing Governance Participant or its Principals, and (iii) has been designated in writing by the Furnishing Governance Participant or by the ISO as confidential either in the document which provided such information, in the transmittal materials accompanying such information, or in a separate document which identifies the information with sufficient specificity and clarity so that the entity receiving such information has been made aware that the Furnishing Governance Participant or the ISO seeks confidential treatment for such information.

(f) Any report, compilation or communication produced by the ISO or a Stakeholder Committee that contains information described in Clause (a), (b), (c), (d) or (e) above and allows for the specific identification of the Furnishing Governance Participant or the DR Information Provider.

Confidential Information shall exclude information if and to the extent such information **(1)** is or becomes generally available to the public without any party violating any obligation of secrecy relating to the information disclosed, or **(2)** is received by a Governance Participant in good faith from a third party who discloses such information on a non-confidential basis without violating any obligation of secrecy relating to the information disclosed, or **(3)** is defined as "Public Information," in Section 3, or **(4)** can be shown by the recipient's prior records to have been already known to the recipient other than through disclosure by a third party which would not be subject to exclusion based on (2) above.

Confidential Information, as defined in this Section 2.1, may be provided to specific user groups entitled to information pursuant to Sections (a) through (i) of Section 3.0. Section 3.0 is not intended, however, to add to or vary the criteria specified above. Otherwise, except as specifically provided herein, no other distribution or disclosure of *Confidential Information* shall be permitted by the ISO, Stakeholder Committees or Governance Participants.

2.2 Treatment of Confidential Information

The Governance Participants shall take reasonable measures to assure that all of their employees, representatives, or agents who by virtue of their participation on, or as an alternate on, a Stakeholder Committee have access to *Confidential Information* of another entity that furnished the information, including, as appropriate, a Furnishing Governance Participant, a DR Information Provider or the ISO (the "Furnishing Entity") (1) do not disclose such *Confidential Information* to any other employee, representative, or agent of the same Governance Participant or any other person except as permitted under this Section 2.2 and (2) use such information solely for the purpose of satisfying that person's responsibilities on the Stakeholder Committee. Each Governance Participant shall, upon request by the Participants Committee, provide assurance that the terms of this Section 2.2 are complied with. Any Governance Participant that has furnished *Confidential Information* to Stakeholder Committees may require each recipient to return all or any portion of the *Confidential Information* once it is no longer needed by such recipient to fulfill its responsibilities under the Filed Documents.

Notwithstanding the foregoing, the ISO, the Participants Committee or any Governance Participant may disclose *Confidential Information* of another Governance Participant or the ISO only: **(1)** if such disclosure is permitted in writing by the Furnishing Entity, DR Information Provider or the ISO, as the case may be, or **(2)** if disclosure is required by order of a court or regulatory agency of competent jurisdiction or dispute resolution pursuant to the Filed Documents, or **(3)** as otherwise specifically permitted by this Policy. Any entity subject to this Information Policy shall provide prompt written notice to the Furnishing Entity if that entity either is compelled by order of a court or regulatory agency of competent jurisdiction to disclose, or receives a request seeking to compel disclosure of, *Confidential Information* for which it is not the Furnishing Entity. Further, in recognition that certain Governance Participants are subject to public records and open meeting laws and that certain other demands may be placed on Governance Participants to disclose *Confidential Information*, a recipient of *Confidential Information* of another Governance Participant or the ISO may disclose such *Confidential Information* if and to the extent required by law or requested in writing pursuant to a public records demand or other legal discovery process, provided in either event that the disclosing Governance Participant gives the Furnishing Governance Participant or the ISO prompt written notice of the circumstances that may require such disclosure in time so that the Furnishing Governance Participant or the ISO has a reasonable opportunity to seek a protective order to prevent disclosure.

Notwithstanding anything to the contrary contained in this Section 2.2, the ISO, the Participants Committee, or any Governance Participant may disclose *Confidential Information* to an alternate dispute resolution ("ADR") neutral in an ADR proceeding required or permitted by any New England market rule, including Appendix A, "Market Monitoring, Reporting and Market Power Mitigation," and Appendix B, "Imposition of Sanctions," to Market Rule 1, or to an arbitrator in an arbitration proceeding under the Filed Documents. In addition, the ISO or any Governance Participant may disclose *Confidential Information* to a Dispute Representative as defined in, and permitted by, Section 5 of the Billing Policy. Any such ADR neutral, arbitrator or Dispute Representative must agree to be bound by this Information Policy.

Notwithstanding anything to the contrary in this Information Policy, resource-specific information contained in the data fields of the Forward Capacity Tracking System, but not information provided to the

ISO as separate attachments via the Forward Capacity Tracking System, will be shared with subsequent Lead Market Participants or Project Sponsors for that resource.

Notwithstanding anything to the contrary in the ISO New England Information Policy, the ISO, the Participants Committee, or any Governance Participant may disclose *Confidential Information* as required or permitted to satisfy the "Minimum Criteria for Market Participation" set forth in Section II.A of the ISO New England Financial Assurance Policy.

2.3 Disclosure of Information Regarding Defaulting Governance Participants

Notwithstanding any provision herein to the contrary, the information for release to Governance Participants identified in this Section shall no longer be deemed "*Confidential Information*" pursuant to the Information Policy. For any Governance Participant that is the subject of a voluntary or involuntary bankruptcy petition or has sought relief under bankruptcy or insolvency laws, or that has otherwise defaulted under its arrangements with the ISO, which default is not, or the ISO reasonably concludes will not be, cured within five days of the date of the default, in the case of a Payment Default (as defined in the Billing Policy) or within ten days of the date of its default in the case of any other defaults, the following information with respect to that Governance Participant's obligations shall be disclosed by the ISO to each member and alternate on the Participants Committee, each Governance Participant's billing contacts, appropriate Stakeholder Committee(s) designated by the Participants Committee, and appropriate state regulatory or judiciary authority:

> For the 60 calendar day period prior to the date of the bankruptcy, insolvency petition or other default (the "Default Date") and from the Default Date forward until such time as the Governance Participant cures the default: **(i)** the type and available amount of financial assurance in place; **(ii)** any notification provided by such Governance Participant pursuant to the Financial Assurance Policy and/or Billing Policy to the ISO of a material change in its financial status; **(iii)** any change in the type or available amount of financial assurance provided by such Governance Participant; **(iv)** whether such Governance Participant has defaulted on its payment obligations under the Billing Policy, the amount of any such default, the date of the default, and when or whether the default is cured; **(v)** whether such Governance Participant has defaulted on its obligations under the Financial Assurance Policy, the amount of any such default, the date of the default, and when or whether the default is cured; **(vi)** where the financial assurance provided by such Governance Participant is a bond, whether the ISO has provided notice of default to the surety and whether the surety has given notice of termination of the bond or otherwise disclaimed or refused to honor or

delayed in honoring its obligations under the bond, and the response of the ISO to any such notice; **(vii)** whether such Governance Participant is a net seller or purchaser in the New England Markets; **(viii)** the amount of such Governance Participant's purchases in the New England Markets; and **(ix)** whether such Governance Participant owns a registered Load Asset.

If a Governance Participant is suspended from the New England Markets, the ISO immediately shall send notice of such suspension to each of the members and alternates on the Participants Committee, the energy regulatory agencies in each of the New England states and the Federal Energy Regulatory Commission. Said notice shall identify the specific date and time of the suspension.

2.4 Breach of Confidential Information Obligations

The Governance Participants and the ISO acknowledge that remedies at law for any breach of the obligations under this Section 2 would be inadequate and agree that, in enforcing this Section 2, in addition to any other remedies provided at law:

(a) A Furnishing Governance Participant may, at its option, take one or both of the following actions: **(i)** apply to any court of equity having jurisdiction for an injunction restraining the ISO, any Stakeholder Committee or any Governance Participant from an actual or threatened violation of this Section 2 relating to *Confidential Information* provided by such Furnishing Governance Participant and **(ii)** submit such actual or threatened violation to arbitration in accordance with the procedure provided in Section 17.3 of the Participants Agreement and Section I of the Transmission, Markets and Services Tariff.

(b) The ISO may, at its option, take one or both of the following actions: **(i)** apply to any court of equity having jurisdiction for an injunction restraining a Governance Participant or any Stakeholder Committee from an actual or threatened violation of this Section 2 relating to *Confidential Information* and **(ii)** submit such actual or threatened violation to arbitration in accordance with the procedure provided in Section 17.3 of the Participants Agreement and Section I of the Transmission, Markets and Services Tariff.

(c) The Participants Committee may, at its option, take one or both of the following actions: **(i)** apply to any court of equity having jurisdiction for an injunction restraining the ISO from an actual or threatened violation of this Section 2 relating to *Confidential Information* and **(ii)** submit such actual or threatened violation to arbitration in accordance with the procedure provided in Section

17.3 of the Participants Agreement and Section I of the Transmission, Markets and Services Tariff.

Section 3 -Information Access

3.0 Information Access

(a) Public Information

This information includes:

- Public record filings with regulatory agencies. (Some examples include, but are not limited to, ISO Budget Data required for ISO Tariff Filings; and data associated with the Open Access Transmission Tariff.)

- Data posted on the Open Access Same-Time Information System ("OASIS"). (Some examples include, but are not limited to, Transmission Facilities Information including System Inventory; New Applications; Scheduling Information, Real Time Tie Line Use and Surplus Availability; Aggregate MW of generation operating out of merit (for transmission, reliability, and VAR) by Reliability Region (these Regions will be defined by the ISO, such that no *Confidential* or Strategic Information is released), Real Time Operating Reserve Availability and curtailment or interruption of External Transactions.)

- Information and/or reports that are required to be filed with the Federal Energy Regulatory Commission ("FERC") (unless specifically required to be filed on a confidential basis). (For example, the Filed Documents.)

- Public Generator Information including System Inventory and New Applications. (Some examples include, but are not limited to, Capacity, Energy, Loads & Transmission (CELT) Report; and 18.4 Applications.)

- Public Market Information includes any items required to be made public by **(i)** the Filed Documents; **(ii)** other relevant documents, including without limitation the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England system and administration of the Market and the Filed Documents; and **(iii)** the items listed in Aggregate Market

Results, as posted under "Market Information" on the ISO website pursuant to this Information Policy. (Some examples include, but are not limited to, aggregate Market requirements and settlements; Clearing Prices; Locational Marginal Prices; lists of load zones, nodes and hubs; Emergency Energy notices; market monitoring input assumptions and threshold values; Financial Transmission Rights modeling and auction results; Auction Revenue Rights modeling and auction results; information relating to the Load Response Program; ICAP Market Schedules and UCAP auction results.)

- In addition, the System Operator shall publish each month's bid and offer information for all markets on its website on the first day of the fourth calendar month following the month during which the applicable demand bids and supply offers were in effect (e.g., bid and offer data for January would be released on May 1), provided that the information is presented in a manner that does not reveal the specific load or supply asset, its owners, or the name of the entity making the bid or offer, but that allows the tracking of each individual entity's bids and offers over time.

- Market test information including any information equivalent to Public Market Information derived from test programs for new markets or market software or simulations of proposed market improvement (includes any and all information necessary for evaluation of the impacts of a proposed new market or an improvement to an existing market, such as cost-shifting impacts and price impacts under certain conditions).

- Long-term system planning and operations information consisting of load forecasts, transmission models (including power flow, short circuit and stability models and their related base cases and contingency files), transfer limits used for planning purposes, Installed Capacity Requirements and Governance Participants and non-Governance Participants proposed generation. This information does not include near-term transmission models or transfer limits within New England that are developed as part of system operations or real-time information from the control room energy management system.

- Public Reports required by the Filed Documents (including, but not limited to, evaluation of procedures for determination of Locational Marginal Prices as well as the awarding Financial Transmission Rights and associated Congestion Costs and Transmission Congestion Credits).

- Public Market Monitoring Information including, but not limited to, public reports by the Independent Market Advisor required by the Market Rules (includes the ISO's time and expenses in pursuing sanctionable behavior on a case-by-case basis and periodic reports of sanctions imposed and the sanctionable behavior upon which such sanctions were imposed, provided that the information is presented in a manner that does not allow for the identification of the Governance Participants by name or provide a manner for identifying such Governance Participants, except as otherwise provided in the Filed Documents).

- Any other information that is not *Confidential Information* that the ISO determines is appropriate for public dissemination because it will improve system reliability, the efficiency of the markets or public understanding of the New England system and the operations of the ISO.

This data may be made available to the public at large. (Fees may be applicable to cover process and handling expenses.) [This information corresponds to the MIS security rule "PB" Public.]

(b) Non-Public Transmission Information

This information includes:

- Information and/or reports that are filed with the North American Electric Reliability Council (NERC). (Some examples include, but are not limited to, all NPCC data, see examples below.)

- Information and/or reports that are filed with the Northeast Power Coordinating Council (NPCC).

- Real-time system operations information, which is not posted on the OASIS, including but not limited to detailed operations data. (Some examples include, but are not limited to, real-time transmission line flows, real-time transfer limits, and real-time voltages.)

- Information relating to specific Generating facilities, which is required by transmission personnel to ensure the reliable operation of the New England bulk power system. (Some examples include, but are not limited to, detailed Generator operating characteristics; and dynamic swing recorder plots.)

- Transmission Operating Guides. (Some examples include, but are not limited to, guides for operation of Special Protection Systems; and transmission operations related to Stability Limits.)

- Information related to system restoration efforts. (Some examples include, but are not limited to, ISO and Governance Participants' detailed Power System Restoration Plans.)

This information may be made available to Reliability Councils and all Governance Participants' Transmission Personnel. The release of relevant transmission outage information to affected generators, to the extent required or desired for coordination of transmission and generation outages, shall be governed by the processes available for such coordination (OP3 or any successor or similar document), by the Codes of Conduct and by other applicable FERC regulation. There is no direct correlation to the MIS Security Rules and there is currently no specific transmission information distributed via the MIS.

(c) Governance Participant Specific Data

This information includes:

- Data not yet posted on the OASIS. (Some examples include, but are not limited to, Interface Transmission Service Schedules Lists.)

- *Confidential Information*, as defined in Section 2.1 of this Policy, for which this Governance participant, or an Agent thereof, has the right to receive the data. (Some examples include, but are not limited to, Product Obligation; and Load.)

- Invoice and Settlement Data. (Some examples include, but are not limited to, Governance Participant Phase I/II Hourly Transfer Capability Allocations; Electrical Load, Adjusted Net Interchange, Obligation, Entitlement, Charges, and Payments for each market.)

[This data may be made available to active users or agents of the specified Governance Participant. This information corresponds to the MIS security rule "SM" Settlement Rule.]

(d) Asset Specific Information – Near Real-Time

This information includes:

- Near real-time information related to the particular asset. (Some examples include, but are not limited to, Generation Levels (MW); Designations (MW); Automatic Generation Control Status, Operating Limits, Response Rates, unit forecast and operation information, and Real Time Status of External

Contract Sales and/or Purchases for which a Governance Participant has a contract on file with the ISO.)

This data may be made available to those Governance Participants, or Agents thereof, who are joint Owners and/or Entitlement Holders in the Asset. [This information corresponds to the MIS security rules "OS" Ownership Rule, "RS" Responsible Party Rule and an Entitlement Holder Rule, currently not identified in the MIS security rules. As applicable, this data may also be made available to a Governance Participant who is a contractual party to external or internal bilateral contracts for the specified Asset, which corresponds to the MIS security rule "TH" Transaction Holder Rule.] The release of relevant generation outage information to affected transmission owners, to the extent required or desired for coordination of transmission and generation outages, shall be governed by the processes available for such coordination (OP3 or any successor or similar document), by the Codes of Conduct and by other applicable FERC regulation.

(e) Asset Specific Information – Forecast and post-Settlement

This information includes:

- Unit Forecast information relating to a particular Asset, which is necessary to determine the projected operation of particular Generators. (Some examples include, but are not limited to, Start Time; Generation; and Shut-Down Time.)

- Information relating to a particular Asset, which is necessary to determine the accuracy of Settlement. (Some examples include, but are not limited to, High Operating Limit; Generation; Ownership Share; and Duration on Automatic Generation Control.)

- Governance Participant input data. (Some examples include, but are not limited to, generation input data; and records of deficient performance.)

- Capability Responsibility (CR) data and calculations, for those specific Generating facilities for which a Governance Participant(s) has an ownership interest. (Some examples include, but are not limited to, Unit Capability Demonstrations and Audits; and Seasonal Claimed Capability.)

- All information, with the exception of bids, offers and meter data, necessary to verify Settlement data. (Some examples include, but are not limited to, Response Rate data; and Minimum Run-Time data.)

This data may be made available to those Governance Participants, or Agents thereof, who are joint Owners and/or Entitlement Holders in the Asset. [This information corresponds to the MIS security rules "OS" Ownership Rule, "RS" Responsible Party Rule and an Entitlement Holder Rule, currently not identified in the MIS security rules.] The release of relevant generation outage information to affected transmission owners, to the extent required or desired for coordination of transmission and generation outages, shall be governed by the processes available for such coordination (OP3 or any successor or similar document), by the Codes of Conduct and by other applicable FERC regulation.

(f) Meter, Bid and Offer Data

This information includes:

- *Confidential Information* submitted as input to the Market System. Bid and offer data may be made available to any Governance Participant with a Generation Ownership Share, or Agent thereof, for a specified Asset. [This information corresponds to the MIS security rules "RS" Responsible Party Rule.]

- Meter data may be made available to the Assigned Meter Reader for a specified Asset. There is no direct correlation to the MIS Security Rules and there is currently no specific MIS distribution of meter data. However, meter data may be manually distributed to the Host Participant whose unmetered load is calculated based on said meter data.

(g) Reliability, Operations and Area Control Information

(i) External Control Center Information

This information includes:

- All System Operations or Planning Information that relates to the particular external Control Center. (Some examples include, but are not limited to, transmission interface transfers and limits within the external control center area; and Inter-Area Emergency Assistance available, used for Planning purposes, under OP-4 conditions.)

- Information that is required to assure the reliable operation of the interconnected bulk power system. (Some examples include, but are not limited to, all information deemed necessary in the event of OP

4 implementation; and, under non-OP-4 system conditions, information related to Inter-Area flow control.)

- Inter-area Transmission Operating Guides that relate to the particular external control area. (Some examples include, but are not limited to, PV-20 Cross Trip SPS – available to New York; and Phase I Runback SPS – available to Hydro Quebec.)

- *Confidential Information* (under signature of confidentiality agreements that provide rights to Governance Participants equivalent to those granted in this Information Policy to notice of and opportunity to defend against any release of their *Confidential Information*) and non-confidential information may be shared among Control Areas for the purposes of increasing markets coordination, including elimination of seams, increasing market efficiency and study purposes of the interconnected bulk power system. (Some examples include, but are not limited to, ISO operations and markets information, including market monitoring information, provided that market monitoring information shall only be shared with independent market operators or independent market monitors and only in connection with particular investigations affecting regional markets.)

There is no direct correlation to the MIS Security Rules and there is no specific MIS distribution of External Control Center Information. This information is not available to Governance Participants, a subset thereof, or the Public at large, but is typically communicated by the ISO Operations (Control Room/Forecast Office) or Planning Department directly to External Control Center personnel.

(ii) Internal (Satellites) Control Center Information

This information includes:

- All System Operations or Planning Information. (Some examples include, but are not limited to, detailed system models; and transmission element data as detailed on the NX-9 forms.)

- Information relating to specific Generating facilities that is needed to assure the reliable operation of the New England Control Area. (Some examples include, but are not limited to, Generator constraints, including the reason for such constraint; and detailed Generator unit commitment.)

- Transmission Operating Guides. (Some examples include, but are not limited to, guides for operation of Special Protection Systems; and transmission operations related to Stability Limits.)

- New England and Satellite System Restoration Plans. (Some examples include, but are not limited to, the ISO, Satellite and Governance Participants' detailed Power System Restoration Plans.)

There is no direct correlation to the MIS Security Rules and there is no specific MIS distribution of Internal (Satellite) Control Center Information. This information is not available to Governance Participants, a subset thereof, or the Public at large, but is typically communicated by the ISO Operations (Control Room/Forecast Office) directly to Satellite personnel.

(h) Load Response Provider Information

This information is asset-specific Confidential Information, including:

- Retail customer information~~.~~;
- Customer data~~.~~;
- Load profiles, and~~.~~;
- Demand response information provided at the request of the Internal Market Monitor pursuant to Section III.A.12.

~~This information~~ Information relating to retail customers, customer data and load profiles is subject to certain state law restrictions and is not available to Governance Participants, a subset thereof, or the public at large, but is typically communicated by the ISO Operations (Control Room/Forecast Office) directly to Load Response Provider personnel.

(i) ISO New England Information

This information includes:

- Any Governance Participant or Asset specific information as requested by the ISO, which will be maintained in accordance with this Policy. (Some examples include, but are not limited to, all Governance Participant and Asset specific information, which is available to the ISO.)

- Any ISO Employment Information and ISO Administrative Information not specifically listed in other categories.

ISO personnel, Consultants, Counsel, and Board Members may have access to any information defined in the categories listed above. This information corresponds to the MIS security rule "ISO" ISO New England.

All *Confidential Information*, as defined in Section 2.1 of this Policy, will only be distributed in accordance with this Policy.

All other data, which is not specifically defined and is not *Confidential Information*, may be released at the discretion of the ISO in accordance with the procedures set forth in Sections 3.1, 3.2 and 3.3 hereto.

(j) Critical Energy Infrastructure Information ("CEII")

This information includes:

- Information designated by a Governance Participant or the ISO as CEII, which is defined by FERC as "specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that: (1) relates details about the production, generation, transportation, transmission, or distribution of energy; (2) could be useful to a person in planning an attack on critical infrastructure; (3) is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552 (2000); and (4) does not simply give the general location of the critical infrastructure."

- Reports, summaries, compilations, analyses, notes or other information which contain such information.

Access to CEII shall be granted by the ISO in accordance with the CEII disclosure processes posted on its website and, in the event that the CEII also falls within a category of information (including *Confidential Information*) described herein, in accordance with this Information Policy. Governance Participants shall treat CEII as if it were *Confidential Information*, notwithstanding any other provision of this Information Policy, and additionally shall maintain CEII in a secure place.

3.1 Information Requests

(a) Requesting Entities

As used in this Section 3.1, the term "Requesting Entity" shall mean any entity (other than the FERC or an Authorized Person, as defined in Section 3.3 of this Information Policy) that requests information from the ISO.

(b) Public Information

If a Requesting Entity requests that the ISO publish Public Information (as defined in Section 3.0(a) of this Information Policy) that is not currently published by the ISO, the ISO may after consultation with the Participants Committee or its designated subcommittee or working group defer or deny such request if the ISO determines that publication of such data is not feasible at the time of such request due to resource limitations, including, without limitation, available software.

(c) Non-Public Information

(i) A Requesting Entity that desires to make a formal request for information that is not Public Information from the ISO, the resolution of which request shall be appealable under Section 3.1(e)(v) of this Information Policy, shall submit a formal written request to the ISO in the manner set forth in Section 3.1(d) below (a "Formal Information Request") for such information.

(ii) Requests for information from Requesting Entities to the ISO other than Formal Information Requests need not be in writing.

(iii) Any request for information from the FERC or from an Authorized Person (as defined in Section 3.3 of this Information Policy) shall be addressed according to the procedures set forth in Section 3.2 and Section 3.3 of this Information Policy, respectively.

(d) Form of Request; Tracking

(i) Any Formal Information Request shall be directed to the point of contact designated by the ISO to handle such requests (the "ISO Information Contact"). The ISO shall post contact information for the ISO Information Contact on the ISO website.

(ii) A Formal Information Request shall be in writing, which shall include electronic communications addressed to the ISO Information Contact, and shall: (a) describe with particularity the information sought; (b) provide a description of the purpose of the information request; (c) state the time period for which such information is requested; (d) specifically designate such request as a Formal Information Request and make reference to Section 3.1(d)(ii) of the Information Policy; and (e) provide contact information for the person to whom the response to such Formal Information Request is to be directed.

(iii) The ISO Information Contact shall track all Formal Information Requests and provide a report indicating the nature of each request and the response to such request to the Markets Committee on a monthly basis.

(e) Timing and Notice

(i) The ISO Information Contact normally shall notify all affected Furnishing Entities within five (5) business days after receiving a Formal Information Request.

(ii) The ISO Information Contact normally shall provide the Requesting Entity with a response (an "Initial Response") within fifteen (15) business days after receiving the Formal Information Request (the "Request Date"). The Initial Response shall indicate either (A) that the ISO has made a decision on the Formal Information Request in accordance with Section 3.1(f)(i) below, in which case it shall describe such decision, or (B) that the ISO was unable to reach a decision, and will be consulting with the Participants Committee in accordance with Section 3.1(f)(ii) below.

(iii) If the Initial Response indicates that the ISO is further consulting with the Participants Committee, the ISO Information Contact normally shall provide the Requesting Entity with a follow-up response (a "Follow-Up Response") the earlier of ten (10) business days after a recommendation by the Participants Committee as set forth in Section 3.1(f)(ii) below or sixty (60) days following the Request Date, which response shall indicate either (A) that the ISO has made a decision on the Formal Information Request in accordance with Section 3.1(f)(ii) below, in which case it shall describe such decision, or (B) that the ISO has failed to make a decision with respect to the Formal Information Request, in which case such request shall be deemed denied.

(iv) The ISO Information Contact shall provide the Furnishing Entity(ies) with copies of any Initial Response or Follow-Up Response provided in response to a Formal Information Request on the same day that such responses are provided to the Requesting Entity. In addition, the ISO Information Contact shall provide the Furnishing Entity(ies) with at least ten (10) business days prior written notice of any release of *Confidential Information* or Strategic Information relating to such Furnishing Entity (whether such release is on the ISO's own initiative, in response to a Formal Information Request, or otherwise), which written notice shall inform such Furnishing Entity(ies) of its right to dispute such release under Section 3.1(e)(v) of the Information Policy.

(v) The Requesting Entity shall have the right to appeal any Initial Response that contains a decision with respect to a Formal Information Request and any Follow-Up Response. Any affected Furnishing Entity shall have the right to appeal any Initial Response or Follow-Up Response that contains a decision with respect to a Formal Information Request and any decision by the ISO to release *Confidential Information* or Strategic Information (whether such release is on the ISO's own initiative, in response to a Formal Information Request, or otherwise). The Participants Committee shall have the right to appeal any Initial Response that contains a decision with respect to a Formal Information Request. Notice of any appeal shall be provided contemporaneously to the Participants Committee and the ISO Information Contact.

(vi) Any appeal of the ISO's actions under this Section 3.1 with respect to a Formal Information Request shall be subject to binding arbitration with FERC's Alternative Dispute Resolution Service, as further described in 18 C.F.R. §§ 385.604, 385.605. The ISO and the disputing entity(ies) shall use reasonable efforts to insure that an arbitrator is selected and a hearing is scheduled within thirty (30) days of the ISO receiving notice of an appeal. Unless otherwise agreed by all parties, the duration of any arbitration hearing will be limited to one day. The arbitrator's decision shall be binding on the respective parties; provided, however, that any of the respective parties to the arbitrator's decision shall be entitled to appeal the arbitrator's decision directly to FERC.

(vii) Suitable forms of notice and/or communications pursuant to this subsection shall include, but not be limited to, electronic communications.

(f) Consideration of Requests

(i) After receiving a Formal Information Request, the ISO shall first determine whether (X) the information requested is information described in Sections (a) through (i) of Section 3.0 and (Y) the Requesting Entity is a member of a user group specifically entitled to receive such information pursuant to Sections (a) through (i) of Section 3.0. If the ISO determines that the Requesting Entity is not entitled to receive the requested information pursuant to Sections (a) through (i) of Section 3.0, the ISO shall then determine if the requested information is *Confidential Information* or Strategic Information. The ISO may consult with the Independent Market Advisor, NEPOOL Counsel, the Furnishing Entity(ies), and/or the Participants Committee (as provided in Section 3.1(d)) during the process of making this determination.

(A) If the ISO determines that the information is *Confidential Information*, the ISO Information Contact will refer the request to the Furnishing Entity(ies) and the ISO will not release the requested information unless it is directed to do so by the Furnishing Entity(ies) or ordered to do so by a court or regulatory authority with jurisdiction over such matters. If the Furnishing Entity(ies) directs the ISO to release the requested information, the ISO will next determine whether the requested information is Strategic Information as set forth in Section 3.1(c)(i)(B) below. The Furnishing Entity(ies) shall bear any costs reasonably incurred by the ISO in opposing the issuance of such an order requiring disclosure of the Furnishing Entity(ies)' *Confidential Information*. Notwithstanding the foregoing, upon the request of a regulatory agency, other than FERC or its staff, having appropriate jurisdiction and subject to an appropriate confidentiality order entered under such agency's procedures sufficient to preserve the confidential nature of the information submitted, and with advance notice to the Furnishing Entity(ies), the ISO Information Contact may submit *Confidential Information* to such agency.

(B) If the information requested is Strategic Information, the ISO shall determine whether to release the requested information, in consultation with the Independent Market Advisor, NEPOOL Counsel and/or the Furnishing Entity(ies), as the ISO deems appropriate. If the ISO releases such information, it will do so by making the information public.

(C) If the information requested is neither *Confidential Information* nor Strategic Information, the ISO shall determine whether to release the requested information; provided that the Participants Committee, acting on the recommendation of an appropriate Stakeholder Committee, may request the ISO to release the requested information.

(ii) If, after consultation with the Independent Market Advisor, NEPOOL Counsel and/or the Furnishing Entity, as appropriate, the ISO cannot, in its good faith judgment, determine the classification status of requested information or otherwise believes that a Formal Information Request raises policy questions that should be determined by the Governance Participants, then the following procedure shall apply:

(A) The ISO shall refer the request to the Participants Committee with its recommendation for action.

(B) The Participants Committee, acting on recommendation of a subcommittee or working group, as appropriate, may approve of or suggest modifications to the recommendation of the ISO. If the Participants Committee approves the ISO's recommendation, or if the ISO accepts the Participants Committee's suggested modifications, the Participants Committee's decision shall determine the response to the Formal Information Request; provided, however, that, to the extent that the information requested is found to be *Confidential Information*, the ISO shall continue to maintain the confidentiality of such information in accordance with the terms of this Information Policy.

(g) Release of Information; Prioritization of Formal Information Requests

(i) The ISO shall reasonably attempt to comply with any Formal Information Request that has been granted within thirty (30) days of the Initial Response or Follow-Up Response informing the Requesting Entity that its request has been granted. The ISO may condition the release of any information to a Requesting Entity upon payment of the ISO's reasonable cost to identify and prepare such information.

(ii) If the ISO does not have the resources available to comply with all outstanding Formal Information Requests within the time provided in clause (i) above, the ISO will consult with the Participants Committee or its designated subcommittee or working group to determine how such Formal Information Requests should be prioritized.

(h) Definition of Strategic Information

For purposes of this Policy, Strategic Information means any information, except Public Information, that would affect a Governance Participant's bid or offer strategy in the New England electric markets including information affecting the offer price for or cost of operation of a resource, the capacity or availability of a resource, or any other offer parameter for a resource.

Strategic Information includes *Confidential Information* supplied by Governance Participants to the extent such information would affect a Governance Participant's bid or offer strategy such as, for example:

- All offer prices and parameters for particular resources including bid blocks and times.
- Cost information regarding operation of one or more resources if and to the extent supplied to the ISO.
- Information regarding fuel availability for thermal resources or impoundment levels for hydroelectric facilities.
- Information regarding transmission outages, not otherwise made public, for scheduled maintenance or otherwise that affects the availability of certain generating resources.

Strategic Information may also include information calculated or produced by the ISO such as:

- Aggregate prices and quantities offered that are derived through the unit commitment process.
- Information regarding which resources will run or have run during any particular market settlement period.
- Information derived through the unit commitment process or the market settlement system as to units that run out of merit.
- Information regarding the existence or location of certain short-term transmission constraints.

No Strategic Information that is *Confidential Information* will be released except in compliance with the provisions of this Information Policy regarding *Confidential Information*.

3.2 Disclosure to FERC

If the FERC or its staff, during the course of an investigation or otherwise, requests information from the ISO that is *Confidential Information* or CEII, the ISO shall provide the requested information to the FERC or its staff, within the time provided for in the request for information. In providing *Confidential Information* to FERC or its staff, the ISO shall, consistent with 18 C.F.R §§ 1b.20 and 388.112, request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure. The ISO shall notify any affected Furnishing Entity(ies) (1) when it is notified by FERC or its staff, that a request for disclosure of *Confidential Information* has been received at which time the ISO and the affected Furnishing Entity(ies) may respond before such information would be made public; and (2) when it is notified by FERC or its staff that a decision to disclose *Confidential Information* has been made, at which time the ISO and the affected Furnishing Entity(ies) may respond before such information would be made public. In providing CEII to FERC or its staff, the ISO shall, consistent with 18 CFR § 388.112, request that the information be treated as CEII by the FERC and its staff.

3.3 Disclosure to Authorized Persons

(a) Definitions

For purposes of this Section 3.3, the following terms shall have the meanings set forth below:

"Affected Governance Participant" shall mean a Governance Participant, which, as a result of its Participation in the markets administered by the ISO, provided Confidential Market Information to the ISO, which Confidential Market Information is requested by or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

"Authorized Commission" shall mean a State public utility commission within the geographic limits of the New England Control Area that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State.

"Authorized Person" shall mean a person who has executed a Non-Disclosure Agreement, and is authorized in writing by an Authorized Commission to receive and discuss Confidential Market Information. Authorized Persons may include attorneys representing an Authorized Commission, consultants and/or contractors directly employed by an Authorized Commission, provided; however, that consultants or contractors may not initiate requests for Confidential Market Information from the ISO or the IMMU.

"Confidential Market Information" shall mean *Confidential Information* consisting of market data relating to the markets administered by the ISO, including data supplied by Governance Participants and aggregate data regularly compiled by the ISO. Confidential Market Information shall not include the following categories of information without excluding any objective market data associated with them that would otherwise be provided under the first sentence of this definition: (i) draft versions of reports and analyses, (ii) internal ISO documents not related to market data, (iii) attorney-client communications, (iv) attorney work-product privileged information, (v) communications about Confidential Market Information between an Affected Governance Participant and the ISO/IMMU, except to the extent that the communications become part of final written reports or final written analyses by the ISO/IMMU, (vi) communications between an Affected Governance Participant and the ISO made on a confidential basis as part of a settlement proceeding or negotiation; and (vii) information provided to the ISO on a confidential basis as part of an Alternative Dispute Resolution proceeding.

"Information Request" shall mean a written request, in accordance with the terms of this Section 3.3 for disclosure of Confidential Market Information pursuant to Section 3.3 of this Information Policy.

"Non-Disclosure Agreement" shall mean an agreement between an Authorized Person and the ISO pursuant to Section 3.3 of this Information Policy, the form of which is appended to this Information Policy (Appendix A), wherein the Authorized Person is given access to otherwise restricted Confidential Market Information, for the benefit of their respective Authorized Commission.

"State Certification" shall mean the Certification of an Authorized Commission, pursuant to Section 3.3 of this Information Policy, the form of which is appended to this Information Policy (Appendix B), wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

"Third Party Request" shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of Confidential Market Information provided to the Authorized Person or Authorized Commission by the ISO or IMMU. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for Confidential Market

Information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

(b) Procedures

(i) Notwithstanding anything in this section to the contrary, the ISO and/or the External Market Monitor shall disclose Confidential Market Information, otherwise required to be maintained in confidence pursuant to this Information Policy, to an Authorized Person under the following conditions:

(1) The Authorized Person has executed a Non-Disclosure Agreement with the ISO representing and warranting that he or she: (i) is an Authorized Person; (ii) is duly authorized to enter into and perform the obligations of the Non-Disclosure Agreement; (iii) has adequate procedures to protect against the release of any Confidential Market Information received, (iv) is familiar with, and will comply with any applicable procedures of the Authorized Commission which the Authorized Person represents, (v) covenants and agrees on behalf of himself or herself not to disclose the Confidential Market Information and to deny any Third Party Requests and defend against any legal process which seeks the release of any Confidential Market Information received in contravention of the terms of the Non-Disclosure Agreement, and (vi) is not in breach of any Non-Disclosure Agreement entered into with the ISO.

(2) The Authorized Commission employing or retaining the Authorized Person has provided the ISO with: (a) a final order of FERC prohibiting the release by the Authorized Person or the Authorized Commission of Confidential Market Information in accordance with the terms of this Information Policy and the Non-Disclosure Agreement; and (b) either an order of such Authorized Commission or a certification from counsel to such Authorized Commission, confirming that the Authorized Commission (i) has statutory authority to protect the confidentiality of any Confidential Market Information received from public release or disclosure and from release or disclosure to any other entity, (ii) will defend against any disclosure of Confidential Market Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders, (iii) will provide the ISO with prompt notice of any such Third Party Request or legal proceedings and will consult with the ISO and/or any Affected Governance Participant in its efforts to deny the Third Party

Request or defend against such legal process, (iv) in the event a protective order or other remedy is denied, will direct Authorized Persons authorized by it to furnish only that portion of the Confidential Market Information which their legal counsel advises the ISO in writing is legally required to be furnished, (v) will exercise its best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Market Information and (vi) has adequate procedures to protect against the release of such Confidential Market Information; and (c) confirmation in writing that the Authorized Person is authorized by the Commission to enter into the Non-Disclosure Agreement and to receive Confidential Market Information under this Information Policy.

(3) The Authorized Commission employing or retaining the Authorized Person has provided the ISO with a State Certification.

(4) The ISO and the External Market Monitor shall be expressly entitled to rely upon such FERC and Authorized Commission orders, the State Certification and/or certifications of counsel in providing Confidential Market Information to the Authorized Person, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder due to the ineffectiveness of the FERC and/or Commission orders, or the inaccuracy of such certification of counsel.

(5) The Authorized Person may discuss Confidential Market Information with other Authorized Persons who are parties to Non-Disclosure Agreements, provided; however, that the ISO shall have confirmed in advance and in writing that it has previously released the Confidential Market Information in question to such Authorized Persons. The ISO shall respond to any written request for confirmation within two (2) business days of its receipt.

(6) The ISO shall maintain a schedule of all Authorized Persons and the Authorized Commissions they represent, which shall be made publicly available on the ISO's website or by written request. Such schedule shall be compiled by the ISO, based on information provided by any Authorized Person and/or Authorized Commission. The ISO shall update the schedule promptly upon receipt of information from an Authorized Person or Authorized Commission, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any

inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by the ISO in the compilation and/or maintenance of the schedule.

(ii) The External Market Monitor or other designated representative of the ISO may, in the course of discussions with any Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or their Authorized Commission to determine whether additional Information Requests for information are appropriate. The External Market Monitor or other representative of the ISO will not make any written or electronic disclosures of Confidential Market Information to the Authorized Person pursuant to this section. In any such discussions, the External Market Monitor or other representative of the ISO shall ensure that the individual or individuals receiving such Confidential Market Information are Authorized Persons as defined herein, request that the Authorized Person describe the purpose of the inquiry, orally designate Confidential Market Information that is disclosed, and refrain from identifying any specific Affected Governance Participant whose information is disclosed. The External Market Monitor or other representative of the ISO shall also be authorized to assist Authorized Persons in interpreting Confidential Market Information that is disclosed. The External Market Monitor or representative of the ISO shall provide any Affected Governance Participant and counsel for the Participants Committee with oral notice of any oral disclosure immediately, but not later than one (1) business day after the oral disclosure. Such oral notice to the Affected Governance Participant shall include the substance of the oral disclosure, but shall not reveal any Confidential Market Information of any other Governance Participant and must be received by the Affected Governance Participant before the name of the Affected Governance Participant is released to the Authorized Person, provided; however, the identity of the Affected Party must be made to the Authorized Person within two (2) business days of the initial oral disclosure. The ISO shall provide an Affected Governance Participant and counsel for the Participants Committee with written notice, which shall include electronic communication, of any oral disclosure as soon as possible, but not later than two (2) business days after the date of the oral disclosure.

(iii) As regards Information Requests:

(1) Information Requests to the ISO shall be in writing, which shall include electronic communications addressed to the External Market Monitor or other designated

representative of the ISO, and shall: (a) describe with particularity the information sought; (b) provide a description of the purpose of the Information Request; (c) state the time period for which Confidential Market Information is requested; and (d) re-affirm that only the Authorized Person shall have access to the Confidential Market Information requested. The ISO shall provide an Affected Governance Participant and counsel for the Participants Committee with written notice, which shall include electronic communication, of an Information Request of the Authorized Person as soon as possible, but not later than two (2) business days after the receipt of the Information Request.

(2) Subject to the provisions of section (iii)(3), the ISO shall supply Confidential Market Information to the Authorized Person in response to any Information Request within five (5) business days of the receipt of the Information Request, to the extent that the requested Confidential Market Information can be made available within such period, provided; however, that in no event shall Confidential Market Information be released prior to the end of the fourth (4th) business day without the express consent of the Affected Governance Participant. To the extent that the ISO cannot reasonably prepare and deliver the requested Confidential Market Information within such five (5) day period, it shall, within such period, provide the Authorized Person with a written schedule for the provision of such remaining Confidential Market Information. Upon providing Confidential Market Information to the Authorized Person, the ISO shall either provide a copy of the Confidential Market Information to the Affected Governance Participant(s), or provide a listing of the Confidential Market Information disclosed, provided; however, that the ISO shall not reveal any Governance Participant's Confidential Market Information to any other Governance Participant.

(3) Notwithstanding section (iii)(2), above, should the ISO, an Affected Governance Participant, or the Participants Committee (with respect to an Information Request that applies to multiple Governance Participants) object to an Information Request or any portion thereof, any of them may, within four (4) business days following the ISO's receipt of the Information Request, request, in writing, a conference with the Authorized Commission or the Authorized Commission's authorized designee to resolve differences concerning the scope or timing of the Information Request, provided; however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute.

Should such conference be refused by any participant, or not resolve the dispute, then the ISO, the Affected Governance Participant, the Participants Committee (with respect to an Information Request that applies to multiple Governance Participants) or the Authorized Commission may initiate appropriate legal action at FERC within three (3) business days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at FERC objecting to a particular Information Request shall be designated by the party as a “fast track” complaint and each party shall bear its own costs in connection with such FERC proceeding. If no FERC proceeding regarding the Information Request is commenced within such three day period, the ISO shall utilize its best efforts to respond to the Information Request promptly. During any pending FERC proceeding regarding an Information Request, the ISO shall continue to maintain the confidentiality of the Confidential Market Information subject to such Information Request.

(iv) In the event of any breach of a Non-Disclosure Agreement:

(1) The Authorized Person and/or their respective Authorized Commission shall promptly notify the ISO, who shall, in turn, promptly notify any Affected Governance Participant and counsel for the Participants Committee of any inadvertent or intentional release, or possible release, of Confidential Market Information provided pursuant to any Non-Disclosure Agreement.

(2) The ISO shall terminate such Non-Disclosure Agreement upon written notice to the Authorized Person and his or her Authorized Commission, and all rights of the Authorized Person thereunder shall thereupon terminate, provided; however, that the ISO may restore an individual’s status as an Authorized Person after consulting with the Affected Governance Participant and to the extent that: (i) the ISO determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Person; (ii) there were no harm or damage suffered by the Affected Governance Participant; or (iii) similar good cause shown. Any appeal of the ISO’s actions under this section shall be to FERC.

(3) The ISO, the Affected Governance Participant, and/or the Participants Committee shall have the right to seek and obtain at least the following types of relief: (a)

an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all Confidential Market Information to the ISO.

(4) No Authorized Person shall have responsibility or liability whatsoever under the Non-Disclosure Agreement or this Information Policy for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of Confidential Market Information to persons not authorized to receive it, provided that such Authorized Person is an employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this section (iv)(4) is intended to limit the liability of any person who is not an employee of or a member of an Authorized Commission at the, time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(5) Any dispute or conflict requesting the relief in section (iv)(2) or (iv)(3)(a) above, shall be submitted to FERC for hearing and resolution. Any dispute or conflict requesting the relief in section (4)(3)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

3.4 Disclosure to Academic Institutions

Notwithstanding anything to the contrary set forth herein, the ISO may disclose Confidential Market Information (as defined in Section 3.3), otherwise to be maintained in confidence pursuant to this Information Policy, to a research university (an “Authorized Institution”), solely for the purpose of academic research by Authorized Researchers (as defined below), under the following conditions:

(a) The Authorized Institution has delivered an information request to the ISO in writing (the “Academic Institution Information Request”), which shall include electronic communications addressed to the External Market Monitor, and shall: (i) describe with particularity the information sought; (ii) provide a description of the purpose of the Academic Institution Information Request (“Proposed Research”); (iii) state the time period for which the Confidential Market Information is requested; (iv) specify the individuals that will have access to such Confidential Market Information (the “Authorized Researchers”) and (v) specify the source of funding for the research to be performed with respect to the requested Confidential Market Information.

(b) The ISO shall review the merits of the Academic Institution Information Request and may, in its sole discretion, reject such request without providing notice to affected Governance Participants and the Participants Committee as required in subsection 3.4(c) below.

(c) In the event that the ISO does not initially reject the Academic Institution Information Request pursuant to subsection 3.4(b) above, the ISO shall provide affected Governance Participants and counsel to the Participants Committee with written notice, which shall include electronic communication, of an Academic Institution Information Request as soon as possible, but no later than five (5) business days after receipt of the Academic Institution Information Request. Such notice shall include all of the information contained in the Academic Institution Information Request.

(d) An authorized representative of the Authorized Institution has executed a non-disclosure agreement in the form attached hereto as Appendix C (the "Academic Institution Non-Disclosure Agreement") in which the Authorized Institution (i) represents and warrants that the Authorized Institution (w) will only share the Confidential Market Information with Authorized Researchers identified in the Academic Institution Information Request, solely to be used for the purpose of the Proposed Research; (x) is duly authorized to enter into and perform the obligations of the Academic Institution Non-Disclosure Agreement; (y) has adequate procedures to protect against the release of any Confidential Market Information received; and (z) is not in breach of any other Academic Institution Non-Disclosure Agreement entered into with the ISO; and (ii) covenants and agrees not to disclose the Confidential Market Information and to deny any third-party requests for the Confidential Market Information and defend against any legal process that seeks the release of any Confidential Market Information.

(e) The ISO shall provide affected Governance Participants and counsel to the Participants Committee written notice, which shall include electronic communication, of its determination whether to release Confidential Market Information in response to an Academic Institution Information Request as soon as possible, but no later than five (5) business days following the provision of the notice required in subsection (c) above. Notice of the ISO's determination shall also include all of the information contained in the Academic Institution Information Request, and shall inform the affected Governance Participants of their right to object to such release, as well as the deadline for any such objection and shall specifically state that in the event that the affected Governance Participants do not object to such release, any information released by the ISO pursuant to an Academic Institution Information Request may be subject to publication by the Authorized Institution; provided that such publication may only be made (x) upon written consent of the ISO and (y) if any material the Authorized Institution proposes to publish, which is related to or that relies upon the Confidential Market Information, is sufficiently redacted or summarized in a manner so that it may not be identified. The ISO shall not release Confidential Market Information relating to any affected Governance Participant that objects to such release within ten (10) business days of the ISO's notice of its determination. Following the tenth (10th) business day after providing such notice, the ISO may, in its sole discretion, release Confidential Market Information relating to those affected Governance Participants that have not objected to such release to the Authorized Institution, provided, however, that the ISO shall redact all Confidential Market Information relating to any objecting affected Governance Participants, as applicable.

(f) In the event that an Authorized Institution or any Authorized Researcher publishes any material related to or that relies upon the Confidential Market Information, upon written consent of the ISO in accordance with Section 2.3.4 of the Academic Institution Non-Disclosure Agreement, the ISO shall provide notice to the Participants Committee regarding the medium (e.g., journal) in which the publication has been made.

APPENDIX A

FORM OF NON-DISCLOSURE AGREEMENT

THIS NON-DISCLOSURE AGREEMENT (the "Agreement") is made this ______ day of _______________, 2004, by and between _______________________, an Authorized Person, as defined below, of __________________ (the "State Commission") having jurisdiction within the State of ____________________, with offices at _________________________________ and ISO New England Inc., a Delaware corporation, with offices at One Sullivan Road, Holyoke, Massachusetts, 01040-2841 ("ISO"). The State Commission and ISO shall be referred to herein individually as a "Party," or collectively as the "Parties."

RECITALS

Whereas, ISO serves as the Regional Transmission Organization for the New England Control Area, and operates and oversees wholesale markets for electricity pursuant to the requirements of the ISO Tariff, as defined below; and

Whereas, the External Market Monitor (as defined below) serves as the independent market monitor for ISO's wholesale markets for electricity, and

Whereas, the ISO New England Information Policy requires that ISO and the External Market Monitor maintain the confidentiality of Confidential Market Information; and

Whereas, the ISO New England Information Policy requires ISO and the External Market Monitor to disclose Confidential Market Information to Authorized Persons upon satisfaction of conditions stated in the ISO New England Information Policy, including, but not limited to, the execution of this Agreement by the Authorized Person and the maintenance of the confidentiality of such information pursuant to the terms of this Agreement; and

Whereas, ISO desires to provide Authorized Persons with the broadest possible access to Confidential Market Information, consistent with ISO's and the External Market Monitor's obligations and duties under the ISO New England Information Policy, the ISO Tariff and other applicable FERC directives; and

Whereas, this Agreement is a statement of the conditions and requirements, consistent with the requirements of the ISO New England Information Policy, whereby ISO and the External Market Monitor may provide Confidential Market Information to the Authorized Person.

NOW, THEREFORE, intending to be legally bound, the Parties hereby agree as follows:

1. Definitions

1.1 Affected Governance Participant. A Governance Participant, which as a result of its participation in the markets administered by ISO, provided Confidential Market Information to ISO, which Confidential Market Information is requested by, or is disclosed to an Authorized Person under this Agreement.

1.2 Authorized Commission. A State public utility commission within the geographic limits of the New England Control Area (as that term in defined in the ISO Tariff) that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State.

1.3 Authorized Person. A person , including the undersigned, which has executed this Agreement and that is authorized in writing by an Authorized Commission to receive and discuss Confidential Market Information. Authorized Persons may include attorneys representing an Authorized Commission, consultants and/or contractors directly employed or retained by an Authorized Commission, provided however that consultants or contractors may not initiate requests for Confidential Market Information from ISO or the External Market Monitor.

1.4 Confidential Market Information. Shall mean *Confidential Information* (as defined in the ISO New England Information Policy) consisting of market data relating to the markets administered by ISO, including data supplied by Governance Participants and aggregate data regularly compiled by ISO. Confidential Market Information shall not include the following categories of information without excluding any objective market data associated with them that would otherwise be provided under the first sentence of this definition: (i) draft versions of reports and analyses, (ii) internal ISO documents not related to market data, (iii) attorney-client communications, (iv) attorney work-product privileged information, (v) communications about Confidential Market Information between an Affected Governance Participant and the ISO/External Market Monitor, except to the extent that the communications become part of final written reports or final written analyses by the ISO/External Market

Monitor, (vi) communications between an Affected Governance Participant and ISO made on a confidential basis as part of a settlement proceeding or negotiation; and (vii) information provided to ISO on a confidential basis as part of an Alternative Dispute Resolution proceeding.

1.5 External Market Monitor. Shall have the meaning set forth in the ISO Tariff.

1.6 FERC. The Federal Energy Regulatory Commission.

1.7 Governance Participant. Shall have the meaning set forth in the ISO Tariff.

1.8 ISO New England Information Policy. Shall have the meaning set forth in the ISO Tariff.

1.9 Information Request. A written request, in accordance with the terms of this Agreement for disclosure of Confidential Market Information pursuant to Section 3.3 of the ISO New England Information Policy.

1.10 ISO Tariff. ISO's Transmission, Markets and Services Tariff, as it may be amended from time to time.

1.11 Third Party Request. Any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of Confidential Market Information. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for Confidential Market Information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

2. Protection of Confidentiality.

2.1 Duty to Not Disclose. The Authorized Person represents and warrants that he or she: (i) is presently an Authorized Person as defined herein; (ii) is duly authorized to enter into and perform this Agreement; (iii) has adequate procedures to protect against the release of Confidential Market Information, and (iv) is familiar with, and will comply with, all such applicable State Commission procedures. The Authorized Person hereby covenants and agrees on behalf of himself or herself not to disclose the Confidential Market Information and to deny any Third Party Request and defend against any legal process which seeks the release of Confidential Market Information in contravention of the terms of this Agreement.

2.2 Conditions Precedent. As a condition of the execution, delivery and effectiveness of this Agreement by ISO and the continued provision of Confidential Market Information pursuant to the terms of this Agreement, the Authorized Commission shall, prior to the initial oral or written request for Confidential Market Information by an Authorized Person on its behalf, provide ISO with: (a) a final order of FERC prohibiting the release by the Authorized Person or the State Commission of Confidential Market Information in accordance with the terms of the Operating Agreement and this Agreement; and (b) either an order of the State Commission or a certification from counsel to the State Commission, confirming that the State Commission has statutory authority to protect the confidentiality of the Confidential Market Information from public release or disclosure and from release or disclosure to any other entity, and that it has adequate procedures to protect against the release of Confidential Market Information; and (c) confirmation in writing that the Authorized Person is authorized by the State Commission to enter into this Agreement and to receive Confidential Market Information under the ISO New England Information Policy.

2.3 Discussion of Confidential Market Information with other Authorized Persons. The Authorized Person may discuss Confidential Market Information with other Authorized Persons who have executed non-disclosure agreements with ISO containing the same terms and conditions as this Agreement; provided, however, that ISO shall have confirmed in advance and in writing that ISO has previously released the Confidential Market Information in question to such Authorized Persons. ISO shall respond to any written request for confirmation within two (2) business days of its receipt.

2.4 Defense Against Third Party Requests. The Authorized Person shall defend against any disclosure of Confidential Market Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders. The Authorized Person shall provide ISO, and ISO shall provide each Affected Governance Participant and counsel for the Participants Committee, with prompt notice of any such Third Party Request or legal proceedings, and shall consult with ISO and/or any Affected Governance Participant in its efforts to deny the request or defend against such legal process. In the event a protective order or other remedy is denied, the Authorized Person agrees to furnish only that portion of the Confidential Market Information which their legal counsel advises ISO (and of which ISO shall, in turn, advise any Affected Governance Participants) in writing is legally required to be furnished, and to exercise their best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Market Information.

2.5 Care and Use of Confidential Market Information.

2.5.1 Control of Confidential Market Information. The Authorized Person(s) shall be the custodian(s) of any and all Confidential Market Information received pursuant to the terms of this Agreement from ISO or the External Market Monitor.

2.5.2 Access to Confidential Market Information. The Authorized Person shall ensure that Confidential Market Information received by that Authorized Person is disseminated only to those persons publicly identified as Authorized Persons on Exhibit "A" to the certification provided by the State Commission pursuant to the procedures contained in Section 2.2 of this Agreement.

2.5.3 Schedule of Authorized Persons.

(i) The Authorized Person shall promptly notify ISO of any change that would affect the Authorized Person's status as an Authorized Person, and in such event shall request, in writing, deletion from the schedule referred to in section (ii), below.

(ii) ISO shall maintain a schedule of all Authorized Persons and the Authorized Commissions they represent, which shall be made publicly available on ISO's website and/or by written request. Such schedule shall be compiled by ISO, based on information provided by any Authorized Person and/or Authorized Commission. ISO shall update the schedule promptly upon receipt of information from an Authorized Person or Authorized Commission, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by ISO in the compilation and/or maintenance of the schedule.

2.5.4 Use of Confidential Market Information. The Authorized Person and his or her Authorized Commission shall use the Confidential Market Information solely for the purpose of assisting the Authorized Commission in discharging its legal responsibility to monitor the wholesale and retail electricity markets, operations, transmission planning and siting, and generation planning and siting materially affecting retail customers within the State in which the Authorized Commission has regulatory jurisdiction, and for no other purpose. Without limiting the foregoing, the Authorized Person and his or her Authorized Commission shall not use its right to acquire Confidential Market Information as a means of conducting discovery or providing evidence during an adversarial proceeding against an Affected Governance Participant or any group of Participants. The Authorized Person and his or her Authorized Commission, however, shall not be prevented from using in an adversarial proceeding Confidential Market Information the Authorized Commission has obtained if: (i) such information becomes known in that proceeding through disclosure by entities other than the Authorized Commission; and (ii) the Authorized Commission discloses such Confidential Market Information consistent with the protections and procedures governing the disclosure of Confidential Market Information to parties in that proceeding; or (iii) the information being disclosed no longer meets the definition of Confidential Market Information.

2.5.5 Return of Confidential Market Information. Upon completion of the inquiry or investigation referred to in the Information Request, or for any reason the Authorized Person is, or will no longer be an Authorized Person, the Authorized Person shall (a) return the Confidential Market Information and all copies thereof to ISO, or (b) provide a certification that the Authorized Person has destroyed all paper copies and deleted all electronic copies of the Confidential Market Information, unless such actions are inconsistent with or prohibited by applicable state law, in which case the Authorized Person shall continue to maintain the confidentiality of the Confidential Market Information in accordance with the terms and conditions of this Agreement. ISO may waive this condition in writing if such Confidential Market Information has become publicly available or non-confidential in the course of business or pursuant to the ISO Tariff or order of the FERC.

2.5.6 Notice of Disclosures. The Authorized Person, directly or through the Authorized Commission, shall promptly notify ISO, and ISO shall promptly notify any Affected Governance Participant, of any inadvertent or intentional release or possible release of the Confidential Market Information provided pursuant to this Agreement. The Authorized Person shall take all steps to minimize any further release of Confidential Market Information, and shall take reasonable steps to attempt to retrieve any Confidential Market Information that may have been released.

2.6 Ownership and Privilege. Nothing in this Agreement, or incident to the provision of Confidential Market Information to the Authorized Person pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against, subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Market Information is intended or shall be inferred by the disclosure of Confidential Market Information by ISO, and any and all intellectual property comprising Confidential Market Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of ISO and/or the Affected Governance Participant.

3. Procedure for Information Requests

3.1 Written Requests. Information Requests to ISO shall be in writing, which shall include electronic communications, addressed to the External Market Monitor or other ISO representatives as specified by ISO, with a concurrent copy to ISO's General Counsel, and shall: (a) describe with particularity the information sought; (b) provide a description of the purpose of the Information Request; (c) state the time period for which information is requested; and (d) re-affirm that only the Authorized Person shall have access to the Confidential Market Information requested. ISO shall provide an Affected Governance Participant and counsel for the Participants Committee with written notice, which shall include electronic communication, of an Information Request of the Authorized Person as soon as possible, but not later than two (2) business days after the receipt of the Information Request.

3.2 Oral Disclosures by the External Market Monitor. The External Market Monitor or other ISO representatives as specified by ISO may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the State Commission to determine whether additional Information Requests for information are appropriate. The External Market Monitor or other ISO representative will not make any written or electronic disclosures of Confidential Market Information to the Authorized Person pursuant to this section. In any such discussions, the External Market Monitor or other ISO representative shall ensure that the individual or individuals receiving such Confidential Market Information are Authorized Persons under this Agreement, request that the Authorized Person describe the purpose of the inquiry, orally designate Confidential Market Information that is disclosed and refrain from identifying any specific Affected Governance Participant whose information is disclosed. The External Market Monitor or other ISO representative shall also be authorized to assist Authorized Persons in interpreting Confidential Market Information that is disclosed. ISO or the External Market Monitor shall (i) maintain a written record of oral disclosures pursuant to this section, which shall include the date of each oral disclosure and the Confidential Market Information disclosed in each such oral disclosure, and (ii) provide any Affected Governance Participant and counsel for the Participants Committee with oral notice of any oral disclosure immediately, but not later than one (1) business day after the oral disclosure. Such oral notice to the

Affected Governance Participant shall include the substance of the oral disclosure, but shall not reveal any Confidential Market Information of any other Governance Participant and must be received by the Affected Governance Participant before the name of the Affected Governance Participant is released to the Authorized Person; provided however, the identity of the Affected Party must be made available to the Authorized Person within two (2) business days of the initial oral disclosure. ISO shall provide an Affected Governance Participant and counsel for the Participants Committee with written notice, which shall include electronic communication, of any oral disclosure as soon as possible, but not later than two (2) business days after the date of the initial oral disclosure.

3.3 Response to Information Requests.

3.3.1 Subject to the provisions of Section 3.3.2 below, ISO shall supply Confidential Market Information to the Authorized Person in response to any Information Request within five (5) business days of the receipt of the Information Request, to the extent that the requested Confidential Market Information can be made available within such period; provided however, that in no event shall Confidential Market Information be released prior to the end of the fourth (4th) business day without the express consent of the Affected Governance Participant. To the extent that ISO can not reasonably prepare and deliver the requested Confidential Market Information within such five (5) day period, ISO shall, within such period, provide the Authorized Person with a written schedule for the provision of such remaining Confidential Market Information. Upon providing Confidential Market Information to the Authorized Person, ISO shall either provide a copy of the Confidential Market Information to the Affected Governance Participant(s), or provide a listing of the Confidential Market Information disclosed; provided, however, that ISO shall not reveal any Governance Participant's Confidential Market Information to any other Governance Participant.

3.3.2 Notwithstanding section 3.3.1, above, should ISO or an Affected Governance Participant or the Participants Committee (with respect to an Information Request that applies to multiple Governance Participants) object to an Information Request or any portion thereof, ISO, the Affected Governance Participant and/or the Participants Committee may, within four (4) business days following ISO's receipt of the Information Request, request, in writing (which shall include electronic communication) addressed to the State Commission with a copy to either the Affected Governance Participant, ISO and/or counsel to the Participants Committee, as the case may be, a conference with the State Commission or the State Commission's authorized designee to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the State Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute. Should such conference be refused by any participant, or not resolve the dispute, then ISO, the Affected Governance Participant, the Participants Committee (with respect to an Information Request that applies to multiple Governance Participants) or the State Commission may initiate appropriate legal action at FERC within three (3) business days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. If no FERC proceeding regarding the Information Request is commenced by ISO, the Affected Governance Participant or the State Commission within such three day period, ISO shall utilize its best efforts to respond to the Information Request promptly. During any pending FERC proceeding regarding an Information Request, ISO shall continue to maintain the confidentiality of the Confidential Market Information subject to such Information Request.

3.3.3 To the extent that a response to any Information Request requires disclosure of Confidential Market Information of two or more Affected Governance Participants, ISO shall, to the extent possible, segregate such information and respond to the Information Request separately for each Affected Governance Participant.

4. Remedies.

4.1 Material Breach. The Authorized Person agrees that release of Confidential Market Information to persons not authorized to receive it constitutes a breach of this Agreement and may cause irreparable harm to ISO and/or the Affected Governance Participant. In the event of a breach of this Agreement by the Authorized Person, ISO shall terminate this Agreement upon written notice to the Authorized Person and his or her Authorized Commission, and all rights of the Authorized Person hereunder shall thereupon terminate; provided, however, that ISO may restore an individual's status as an Authorized Person after consulting with the Affected Governance Participant and to the extent that: (i) ISO determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Person; (ii) there were no harm or damages suffered by the Affected Governance Participant; or (iii) similar good cause shown. Any appeal of ISO's actions under this section shall be to FERC.

4.2 Judicial Recourse. In the event of any breach of this Agreement, ISO, the Affected Governance Participant and/or the Participants Committee shall have the right to seek and obtain at least the following types of relief: (a) an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all Confidential Market Information to ISO. The Authorized Person expressly agrees that in the event of a breach of this Agreement, any relief sought properly includes, but shall not be limited to, the immediate return of all Confidential Market Information to ISO.

4.3 Waiver of Monetary Damages. No Authorized Person shall have responsibility or liability whatsoever under this Agreement for any and all liabilities, losses,
damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of, or in connection with, the release of Confidential Market Information to persons not authorized to receive it, provided that such Authorized Person is an employee or Governance Participant of an Authorized Commission at the time of such unauthorized release. Nothing in this Section 4.3 is intended to limit the liability of any person who is not an employee of or a Governance Participant of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

5. Jurisdiction. The Parties agree that (i) any dispute or conflict requesting the relief in sections 4.1 and 4.2(a) above shall be submitted to FERC for hearing and resolution; (ii) any dispute or conflict requesting the relief in section 4.2(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution; and (iii) jurisdiction over all other actions and requested relief shall lie in any court of competent jurisdiction.

6. Notices. All notices required pursuant to the terms of this Agreement shall be in writing, and served at the following addresses or email addresses:

If to the Authorized Person:

-

____

__

____

__

____

__

(email address)

with a copy to

—

—

—

(email address)

If to Counsel for the Participants Committee:

—

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(email address)

with a copy to

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–

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(email address)

If to ISO:

(email address)

with a copy to

(email address)

7. Severability and Survival. In the event any provision of this Agreement is determined to be unenforceable as a matter of law, the Parties intend that all other provisions of this Agreement remain in full force and effect in accordance with their terms. In the event of conflicts between the terms of this Agreement and the Operating Agreement, the terms of the Operating Agreement shall in all events be controlling. The Authorized Person acknowledges that any and all obligations of the Authorized Person hereunder shall survive the severance or termination of any employment or retention relationship between the Authorized Person and their respective Authorized Commission.

8. Representations. The undersigned represent and warrant that they are vested with all necessary corporate, statutory and/or regulatory authority to execute and deliver this Agreement, and to perform all of the obligations and duties contained herein.

9. Third Party Beneficiaries. The Parties specifically agree and acknowledge that each Governance Participant is an intended third party beneficiary of this Agreement entitled to enforce its provisions.

10. Counterparts. This Agreement may be executed in counterparts and all such counterparts together shall be deemed to constitute a single executed original.

11. Amendment. This Agreement may not be amended except by written agreement executed by authorized representatives of the Parties.

ISO NEW ENGLAND INC.	AUTHORIZED PERSON
By:	By:
_______________________________	_______________________________
Name:	Name:
Title:	Title:

APPENDIX B
FORM OF CERTIFICATION

This Certification (the “Certification”) is given this _____ day of ________________, 200_, by ______________________________, a __________________________ (the “Authorized Commission”), to and for the benefit of ISO New England Inc. (“ISO”) and its Governance Participants. The Authorized Commission and ISO shall be referred to herein collectively as the “Parties”.

Whereas, the Authorized Commission has designated the individuals on attached Exhibit “A” (the “Authorized Persons”) to receive Confidential Market Information from ISO, and

Whereas, the Authorized Persons and ISO have, or will, enter into non-disclosure agreements, governing the rights and obligations of the Authorized Persons, ISO and others regarding the Authorized Persons’ access to, provision of, use and control of the Confidential Market Information (the “Non-Disclosure Agreements”), and

Whereas, as a condition precedent to the execution of the Non-Disclosure Agreements and provision of Confidential Market Information to the Authorized Persons, the Authorized Commission is required to make certain representations and warranties to ISO, and

Whereas, ISO agrees to provide Confidential Market Information to the Authorized Persons, in their capacity as agents of the Authorized Commission, subject to the terms of this Certification, the Non-Disclosure Agreements, and an appropriate order of the Federal Energy Regulatory Commission protecting the confidentiality of such data;

Whereas, the Parties desire to set forth those representations and warranties herein.

Now, therefore, the Authorized Commission hereby makes the following representations and warranties, all of which shall be true and correct as of the date of execution of this Certification, and at all times thereafter, and with the express understanding that ISO and any Affected Member shall rely on each representation and/or warranty:

1. Definitions. Terms contained, but not defined, herein shall have the definitions or meanings ascribed to such terms in the Non-Disclosure Agreement or the ISO New England Information Policy.

2. Requisite Authority.

a. The Authorized Commission hereby certifies that it has all necessary legal authority to execute, deliver, and perform the obligations in this Certification.

b. Each Authorized Person is, at the time of the execution of this Certification, an employee of, or consultant to, the Authorized Commission, and has not materially breached any existing or past nondisclosure agreement or obligation, except as has been disclosed by the Authorized Commission to ISO in writing.

c. The Authorized Persons have, through all necessary action of the Authorized Commission, been appointed and directed by the Authorized Commission to execute and deliver the Non-Disclosure Agreements to ISO and receive Confidential Market Information on the Authorized Commission's behalf and for its benefit.

d. The Authorized Commission will, at all times after the provision of Confidential Market Information to the Authorized Persons, provide ISO with: (i) written notice of any changes in the Authorized Persons' qualification as an Authorized Person within two (2) business days of such change; (ii) written confirmation to any inquiry by ISO regarding the status or identification of any specific Authorized Person within two (2) business days of such request, and (iii) periodic written updates, no less often than semi-annually, containing the names of all Authorized Persons appointed by the Authorized Commission.

3. Protection of Confidential Market Information.

a. The Authorized Commission has adequate internal procedures, to protect against the release of any Confidential Market Information by the Authorized Persons or other employee or agent of the Authorized Commission, and the Authorized Commission and the Authorized Persons will strictly enforce and periodically review all such procedures. In the event that ISO terminates a Non-Disclosure Agreement with an Authorized Person, and does not restore such individual's status as an Authorized Person, then the Authorized Commission shall review such internal procedures.

b. The Authorized Commission has legal authority to protect the confidentiality of Confidential Market Information from public release or disclosure and/or from release or disclosure to any other person or entity, either by the Authorized Commission or the Authorized Persons, as agents of the Authorized Commission.

c. The Authorized Commission shall ensure that Confidential Market Information and shall be maintained by, and accessible only to, the Authorized Persons.

d. The Authorized Commission and its Authorized Person(s) shall not disclose the Confidential Market Information.

4. Defense Against Requests for Disclosure. The Authorized Commission shall defend against, and will direct the Authorized Persons to defend against, disclosure of any Confidential Market Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders. The Authorized Commission shall provide ISO with prompt notice of any such Third Party Request or legal proceedings, and shall consult with ISO and/or any Affected Governance Participant in its efforts to deny the request or defend against such legal process. In the event a protective order or other remedy is denied, the Authorized Commission agrees to furnish only that portion of the Confidential Market Information which their legal counsel advises ISO (and of which ISO shall, in turn, advise any Affected Member) in writing is legally required to be furnished, and to exercise then-best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Market Information.

5. Use and Destruction of Confidential Market Information.

a. The Authorized Commission shall use, and allow the use of, the Confidential Market Information solely for the purpose of assisting the Authorized Commission in discharging its legal responsibility to monitor the wholesale and retail electricity markets, operations, transmission planning and siting, and generation planning and siting materially affecting retail customers within the State in which the Authorized Commission has regulatory jurisdiction, and for no other purpose. Without limiting the foregoing, the Authorized Commission shall not use its right to acquire Confidential Market Information as a means of conducting discovery or providing evidence during an adversarial proceeding against an Affected Governance Participant or any group of Participants. The Authorized Commission, however, shall not be prevented from using in an adversarial proceeding Confidential Market Information the Authorized Commission has obtained if: (i) such information becomes known in that proceeding through disclosure by entities other than the Authorized Commission; and (ii) the Authorized Commission discloses such

Confidential Market Information consistent with the protections and procedures governing the disclosure of Confidential Market Information to parties in that proceeding; or (iii) the information being disclosed no longer meets the definition of Confidential Market Information.

b. Upon completion of the inquiry or investigation referred to in any Information Request initiated by or on behalf of the Authorized Commission, or for any reason any Authorized Person is, or will no longer be an Authorized Person, the Authorized Commission will ensure that such Authorized Person either (a) returns the Confidential Market Information and all copies thereof to ISO, or (b) provides a certification that the Authorized Person and/or the Authorized Commission has destroyed all paper copies and deleted all electronic copies of the Confidential Market Information, unless such actions are inconsistent with or prohibited by applicable state law, in which case the Authorized Commission shall continue to maintain the confidentiality of the Confidential Market Information in accordance with the terms and conditions of this Certification.

6. Notice of Disclosure of Confidential Market Information. The Authorized Commission shall promptly notify ISO of any inadvertent or intentional release or possible release of the Confidential Market Information provided to any Authorized Person, and shall take all available steps to minimize any further release of Confidential Market Information and/or retrieve any Confidential Market Information that may have been released.

7. Ownership and Privilege. Nothing in this Certification, or incident to the provision of Confidential Market Information to the Authorized Person pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Market Information is intended or shall be inferred by the disclosure of Confidential Market Information by ISO, and any and all intellectual property comprising Confidential Market Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of ISO and/or the Affected Governance Participant.

Executed, as of the date first set out above.

[Commission]

By:______________________________

Its:_______________________________

[SEE NEXT PAGE]

EXHIBIT A

CERTIFICATION LIST OF AUTHORIZED PERSONS

Name of Authority	Mailing Address	Email	Tel #	Scope and Duration

APPENDIX C

FORM OF ACADEMIC INSTITUTION NON-DISCLOSURE AGREEMENT

THIS NON-DISCLOSURE AGREEMENT (the “Agreement”) is made this ______ day of _______________, 200_, by and between _______________________, (the “Authorized Institution”), with offices at _________________________________ and ISO New England Inc., a Delaware corporation, with offices at One Sullivan Road, Holyoke, Massachusetts, 01040-2841 (the “ISO”). The Authorized Institution and the ISO shall be referred to herein individually as a “Party,” or collectively as the “Parties.”

RECITALS

Whereas, the ISO serves as the Regional Transmission Organization for the New England Control Area, and operates and oversees wholesale markets for electricity pursuant to the requirements of the ISO Tariff, as defined below; and

Whereas, the External Market Monitor (as defined below) serves as the independent market monitor for ISO’s wholesale markets for electricity, and

Whereas, the ISO New England Information Policy requires that the ISO and the External Market Monitor maintain the confidentiality of Confidential Market Information; and

Whereas, the ISO New England Information Policy permits the ISO and the External Market Monitor to disclose Confidential Market Information to the Authorized Institution upon satisfaction of conditions stated in the ISO New England Information Policy, including, but not limited to, the execution of this Agreement by the Authorized Institution and the maintenance of the confidentiality of such information by the Authorized Institution pursuant to the terms of this Agreement; and

Whereas, the ISO desires to provide the Authorized Institution with access to Confidential Market Information, consistent with the ISO’s and the External Market Monitor’s obligations and duties under the ISO New England Information Policy, the ISO Tariff and other applicable FERC directives; and

Whereas, this Agreement is a statement of the conditions and requirements, consistent with the requirements of the ISO New England Information Policy, whereby the ISO may provide Confidential Market Information to the Authorized Institution.

NOW, THEREFORE, intending to be legally bound, the Parties hereby agree as follows:

1. Definitions. Capitalized terms not otherwise defined herein shall have the meanings ascribed thereto in the ISO Tariff.

1.1 Affected Governance Participant. A Governance Participant, which as a result of its participation in the markets administered by the ISO, provided Confidential Market Information to the ISO, which Confidential Market Information is requested by, or is disclosed to an Authorized Institution under this Agreement.

1.2 Authorized Researcher. Shall have the meaning set forth in the ISO New England Information Policy.

1.3 Confidential Market Information. Shall mean *Confidential Information* (as defined in the ISO New England Information Policy) consisting of market data relating to the markets administered by the ISO, including data supplied by Governance Participants and aggregate data regularly compiled by the ISO. Confidential Market Information shall not include the following categories of information without excluding any objective market data associated with them that would otherwise be provided under the first sentence of this definition: (i) draft versions of reports and analyses, (ii) internal ISO documents not related to market data, (iii) attorney-client communications, (iv) attorney work-product privileged information, (v) communications about Confidential Market Information between an Affected Governance Participant and the ISO/External Market Monitor, except to the extent that the communications become part of final written reports or final written analyses by the ISO/External Market Monitor, (vi) communications between an Affected Governance Participant and the ISO made on a confidential basis as part of a settlement proceeding or negotiation, and (vii) information provided to the ISO on a confidential basis as part of an Alternative Dispute Resolution proceeding. If the aforementioned information in (i) through (vii) is furnished to the Authorized Institution, such information shall be protected according to the terms of this Agreement, and the Authorized Institution shall return such information to the ISO as promptly as possible.

1.4 Competitive Duty Personnel. Shall mean a person whose duties include (i) the marketing or sale of electric power at wholesale; (ii) the purchase or resale of electric power at wholesale; (iii) the direct supervision of any employee with duties specified in subparagraph (i) or (ii) of this paragraph; or (iv) the provision of electricity marketing consulting services to entities engaged in the sale or purchase of electric power at wholesale.

1.5 FERC. The Federal Energy Regulatory Commission.

1.6 External Market Monitor. Shall have the meaning set forth in the ISO Tariff.

1.7 Governance Participant. Shall have the meaning set forth in the ISO Tariff.

1.8 ISO New England Information Policy. Shall have the meaning set forth in the ISO Tariff.

1.9 Information Request. A written request by the Authorized Institution in accordance with the terms of this Agreement for disclosure of Confidential Market Information pursuant to Section 3.4 of the ISO New England Information Policy.

1.10 ISO Tariff. The ISO's Transmission, Markets and Services Tariff, as it may be amended from time to time.

1.11 Non-Disclosure Certificate. Shall mean the certificate annexed hereto by which Authorized Researchers who have been granted access to Confidential Market Information shall certify their understanding that such access to Confidential Market Information is provided pursuant to the terms and restrictions of this Agreement, that they are not Competitive Duty Personnel, and that they have read this Agreement and agree to be bound by it.

1.12 Notes of Confidential Market Information. Shall mean memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in the definition of Confidential Market Information set forth above. Notes of Confidential Market Information are subject to the same restrictions provided in this Agreement for Confidential Market Information except as specifically provided in this Agreement.

1.13 Proposed Research. Shall have the meaning set forth in Section 3.4 of the Information Policy.

1.14 Third Party Request. Any request or demand by any entity upon the Authorized Institution for release or disclosure of Confidential Market Information. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for Confidential Market Information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

2. Protection of Confidentiality.

2.1 Duty to Not Disclose. The Authorized Institution represents and warrants that it:
(i) is duly authorized to enter into and perform this Agreement; (ii) has adequate procedures to protect against the release of Confidential Market Information; and (iii) is familiar with, and will comply with, all such applicable procedures. The Authorized Institution hereby covenants and agrees not to disclose the Confidential Market Information and to deny any Third Party Request and defend against any legal process that seeks the release of Confidential Market Information in contravention of the terms of this Agreement.

2.2 Defense Against Third Party Requests. The Authorized Institution shall defend against any disclosure of Confidential Market Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders. The Authorized Institution shall provide the ISO, and the ISO shall provide each Affected Governance Participant and counsel for the Participants Committee, with prompt notice of any such Third Party Request or legal proceedings, and shall consult with the ISO and/or any Affected Governance Participant in its efforts to deny the request or defend against such legal process. In the event a protective order or other remedy is denied, the Authorized Institution agrees to furnish only that portion of the Confidential Market Information which its legal counsel advises the ISO (and of which the ISO shall, in turn, advise any Affected Governance Participants) in writing is legally required to be furnished, and to exercise its best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Market Information.

2.3 Care and Use of Confidential Market Information.

2.3.1 Control of Confidential Market Information. The Authorized Institution shall be the custodian of any and all Confidential Market Information received pursuant to the terms of this Agreement from the ISO or the External Market Monitor.

2.3.2 Access to Confidential Market Information. The Authorized Institution shall ensure that Confidential Market Information received by that Authorized Institution is disseminated only to those persons publicly identified as Authorized Researchers in the applicable Information Request, and that such Authorized Researchers have been advised of the confidential nature of the Confidential Market Information and have agreed to abide by the terms of this Agreement by signing a Non-Disclosure Certificate. The Authorized Institution agrees that it shall be liable for any breach of this Agreement by any of the Authorized Researchers.

2.3.3 Competitive Duty Personnel. If any person who has been an "Authorized Researcher" subsequently becomes Competitive Duty Personnel, that person shall thereafter have no access to Confidential Market Information, shall return all such materials to the Authorized Institution, and shall continue to comply with the requirements set forth in this Non-Disclosure Agreement with respect to Confidential Market Information to which such person previously had access.

2.3.4 Use of Confidential Market Information. The Authorized Institution shall use the Confidential Market Information solely for the purpose of the Proposed Research. An Authorized Researcher may make copies of Confidential Market Information, but such copies become Confidential Market Information. An Authorized Researcher may make notes of Confidential Market Information, which shall be treated as Notes of Confidential Market Information if they disclose the contents of Confidential Market Information. In the event that the Authorized Institution or any Authorized Researcher desires to publish any material related to or that relies upon the Confidential Market Information, the Authorized Institution or Authorized Researcher must ensure that the Confidential Market Information is sufficiently redacted or summarized so that it may not be identified. Any such publication must be approved in writing by the ISO in advance of its release.

2.3.5 Return of Confidential Market Information. Upon completion of the Proposed Research, or upon termination of this Agreement for any reason, the Authorized Institution shall (a) return the Confidential Market Information and all copies thereof to the ISO, or (b) provide a certification that the Authorized Institution has destroyed all paper copies and deleted all electronic copies of the Confidential Market Information. The ISO may waive this condition in writing if such Confidential Market

Information has become publicly available or non-confidential in the course of business or pursuant to the ISO Tariff or order of the FERC.

2.3.6 Notice of Disclosures. The Authorized Institution shall promptly notify the ISO, and the ISO shall promptly notify any Affected Governance Participant, of any inadvertent or intentional release or possible release of the Confidential Market Information provided pursuant to this Agreement.
The Authorized Institution shall take all steps to minimize any further release of Confidential Market Information, and shall take reasonable steps to attempt to retrieve any Confidential Market Information that may have been released.

2.4 Ownership and Privilege. Nothing in this Agreement, or incident to the provision of Confidential Market Information to the Authorized Institution pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against, subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Market Information is intended or shall be inferred by the disclosure of Confidential Market Information by the ISO, and any and all intellectual property comprising Confidential Market Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of the ISO and/or the Affected Governance Participant.

3. Remedies.

3.1 Material Breach. The Authorized Institution agrees that any release of Confidential Market Information to persons not authorized to receive it or any publication of any material related to or that relies upon the Confidential Market Information which is not (i) approved in writing by the ISO prior to publication and (ii) redacted or summarized in such a manner that the Confidential Market Information may not be identified shall constitute a breach of this Agreement and may cause irreparable harm to the ISO and/or the Affected Governance Participant. In the event of a breach of this Agreement by the Authorized Institution, the ISO may terminate this Agreement upon written notice to the Authorized Institution, and all rights of the Authorized Institution hereunder shall thereupon terminate; provided, however, that the ISO may restore status as an Authorized Institution after consulting with the Affected Governance Participant and to the extent that: (i) the ISO determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Institution; (ii) there were no harm or damages suffered by the Affected Governance Participant; or (iii) similar good cause shown.

Notwithstanding the foregoing, the Authorized Institution hereby shall indemnify, save, hold harmless, discharge, and release the ISO and each affected Governance Participant from and against any and all payments, liabilities, damages, losses or costs and expenses paid or directly incurred by the ISO and/or each affected Governance Participant arising from, based upon, related to, or associated with the breach of, or failure to perform or satisfy, any obligation of the Authorized Institution set forth in this Agreement.

3.2 Judicial Recourse. In the event of any breach of this Agreement, the ISO, the Affected Governance Participant and/or the Participants Committee shall have the right to seek and obtain at least the following types of relief: (a) temporary, preliminary, and/or permanent injunctive relief with respect to any breach and (b) the immediate return of all Confidential Market Information to the ISO. The Authorized Institution expressly agrees that in the event of a breach of this Agreement, any relief sought properly includes, but shall not be limited to, the immediate return of all Confidential Market Information to the ISO.

4. Jurisdiction. The Parties agree that jurisdiction over all other actions and requested relief with respect to the Agreement shall lie in any court of competent jurisdiction.

5. Notices. All notices required pursuant to the terms of this Agreement shall be in writing, and served at the following addresses or email addresses:

If to the Authorized Institution:

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(email address)

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with a copy to

___

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(email address)

If to Counsel for the Participants Committee:

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(email address)

with a copy to

_

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(email address)

If to ISO:

(email address)

with a copy to

(email address)

6. **Severability and Survival**. In the event any provision of this Agreement is determined to be unenforceable as a matter of law, the Parties intend that all other provisions of this Agreement remain in full force and effect in accordance with their terms.

7. **Representations**. The undersigned represent and warrant that they are vested with all necessary corporate, statutory and/or regulatory authority to execute and deliver this Agreement, and to perform all of the obligations and duties contained herein.

8. **Third Party Beneficiaries.** The Parties specifically agree and acknowledge that each Governance Participant is an intended third party beneficiary of this Agreement entitled to enforce its provisions.

9. **Counterparts**. This Agreement may be executed in counterparts and all such counterparts together shall be deemed to constitute a single executed original.

10. **Amendment.** This Agreement may not be amended except by written agreement executed by authorized representatives of the Parties.

ISO NEW ENGLAND INC.	AUTHORIZED INSTITUTION
By:	By:
______________________________	______________________________
Name:	Name:
Title:	Title:

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Confidential Market Information is provided to me pursuant to the terms and restrictions of the attached Non-Disclosure Agreement, that I have read such Non-Disclosure Agreement, and that I agree to be bound by it. In addition, I hereby certify that I am not a Competitive Duty Personnel as that term is defined in the Non-Disclosure Agreement. I understand that the contents of the Confidential Market Information, any notes or other memoranda, or any other form of information that copies or discloses Confidential Market Information shall not be disclosed to anyone other than in accordance with that Non-Disclosure Agreement.

By:

____

Title:

____

Representing:

____

Date:__________________________________

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[NOTICE ADDRESS]

Attachment 2

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:

Accepted Electric Industry Practice, sometimes referred to as Good Utility Practice, means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric generation and transmission 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. Accepted Electric Industry Practice is not limited to a single, optimum practice method or act to the exclusion of others, but rather is intended to include practices, methods, or acts generally accepted in the region.

Adjusted Regulation Obligation is equal to a Market Participant’s total Real-Time Load Obligation ratio share of the total amount of Regulation provided that hour, adjusted for any internal bilateral transactions for Regulation.

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.

Amount Interrupted is, for purposes of the Load Response Program, the calculated difference between the Customer Baseline and the actual customer load. For generating assets, metered at the generator output, the Amount Interrupted is the generator output.

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, 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 electricity 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.

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; (iii) the sum of a Critical Peak Demand Resource's electrical energy reduction during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours less 30 minutes for each set of consecutive Real-Time Demand Resource Dispatch Hours within the same Operating Day in the month for that resource; or (iv) 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. 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; (iii) the sum of a Critical Peak Demand Resource's electrical energy output during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours for that resource less 30 minutes for each set of consecutive Real-Time Demand Resource Dispatch Hours within the same Operating Day in the month for that resource; or (iv) 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.

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 the 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); and (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).

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 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 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 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 a load serving entity's initially allocated share of the Installed Capacity Requirement, prior to any Capacity Load Obligation Bilaterals, during a Capacity Commitment Period for a Capacity Zone, as 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.

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

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 the other Covered Entities and for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the generation output level, expressed in MW, which can be reached by a Resource (from an off-line state) within 10 minutes after receiving a Dispatch Instruction or the amount of reduced consumption, expressed in MW, which can be reached by a Dispatchable Asset Related Demand within 10 minutes after receiving a Dispatch Instruction. A CLAIM10 value is required as part of a Resource's or Dispatchable Asset Related Demand's Offer Data. CLAIM10 values are established pursuant to the provisions of Section III.9.5.3.

CLAIM30 is the generation output level, expressed in MW, which can be reached by a Resource (from an off-line state) within 30 minutes after receiving a Dispatch Instruction or the amount of reduced consumption, expressed in MW, which can be reached by a Dispatchable Asset Related Demand within 30 minutes after receiving a Dispatch Instruction. A CLAIM30 value is required as part of a Resource's or Dispatchable Asset Related Demand's Offer Data. CLAIM30 values are established pursuant to the provisions of Section III.9.5.3.

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.

Commitment Offer Test is defined in Section III.A.5.8.3 of Appendix A of Market Rule 1.

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 weekly 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, for purposes of Section II of the Tariff, 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 Council; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Area, for purposes of Section III of the Tariff, is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: (i) 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); (ii) maintain scheduled interchange with other Control Areas, within the limits of Accepted Electric Industry Practice; (iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the applicable regional reliability council or the NERC; and (iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry 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 determined in accordance with Section III.13.2.4 of Market Rule 1.

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.

Critical 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 electrical usage during Demand Resource Critical Peak Hours or shift electrical usage from Demand Resource Critical Peak Hours to other hours and reduce the amount of capacity needed to deliver a comparable or acceptable level of service at those end-use customer facilities. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

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

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

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

Customer Baseline is the average aggregate hourly load, rounded to the nearest kWh, for each of the 24 hours in a day for each Load Response Program Asset participating in the Real-Time Price Response Program, and the average aggregated five-minute load, rounded to the nearest kWh, for each of the 24 hours in a day for Real-Time Demand Response Assets and Real-Time Emergency Generation Resource assets.

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.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(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 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.

Demand Reduction Value is the quantity of reduced demand, measured at the end-use customer meter, produced by a Demand Resource, which is calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

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

Demand Resource is a resource defined as On-Peak Demand Resources, Seasonal Peak Demand Resources, Critical 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 during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Demand Resource Critical 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 Critical Peak Hours means Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours.

Demand Resource Financial Assurance Requirement is an amount of financial assurance required from DRP-Only Customer registering a Demand Resource in the Day-Ahead Energy Market. This amount is calculated pursuant to Section VIII.A of the ISO New England Financial Assurance Policy.

Demand Resource Forecast Peak Hours means those hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and Real-Time Demand Response Resources, 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, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours by 10:00 p.m. on the day before the relevant Operating Day. Beginning on June 1, 2011, **Demand Resource Forecast Peak Hours** are those hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and 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, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours by 10:00 p.m. on the day before the next Operating Day.

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-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 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.8.

Demand Response Holiday is a holiday for which a Market Participant may not submit a Demand Reduction Offer for a Real-Time Demand Response Asset.

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 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 or DRP-Only Customer 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 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 billing 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, Demand Resource Critical 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. Distributed Generation resources are not eligible for energy payments from ISO-administered energy markets. Generation resources cannot participate in the Forward Capacity Market as Demand Resources, unless they meet the definition of Distributed Generation.

DRP-Only Customer is a Market Participant that enrolls itself and/or one or more Demand Resources in the Load Response Program and that does not participate in other markets or programs of the New England Markets, provided, however, that a DRP-Only Customer may also be an FTR-Only Customer and/or an ODR-Only Customer. References in this Tariff to a Non-Market Participant demand response provider or similar phrases shall be deemed references to a DRP-Only Customer.

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 prices of 0.8 times CONE or lower, as described in Section III.13.2.3.2(d) of Market Rule 1.

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 – (average of max and min Effective Temperature of the day).

Effective Temperature is equal to dry bulb temperature – [windspeed X (65-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, for purposes of Section II of the Tariff, is an abnormal condition on the bulk power system(s) of New England and/or neighboring control areas that, if not immediately corrected, could lead to the shedding of firm electrical load. Such abnormal conditions are beyond the reasonable control and ability to avoid of the system operator of the region(s) experiencing such conditions. Such conditions could result from emergency outages of generating units, transmission lines or other equipment, or other such unforeseen circumstances such as load forecast errors.

Emergency, for purposes of Section III of the Tariff, is an abnormal system condition 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.

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.

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.

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.

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.

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.

FCM Pivotal Supplier shall mean a Lead Market Participant whose total Qualified Capacity from its Existing Capacity Resources in a Capacity Zone minus the quantity of its capacity subject to Non-Price Retirement Requests in that Capacity Zone for the current Forward Capacity Auction is greater than the difference between the total MW from qualified Existing Capacity Resources in the Capacity Zone minus the sum of the quantity of capacity subject to Non-Price Retirement Requests in that Capacity Zone plus the Local Sourcing Requirement for that Capacity Zone.

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 Critical Peak Demand

Resource, Real-Time Demand Response Resource, and Real-Time Emergency Generation Resource, 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, provided, however, that an FTR-Only Customer may also be a DRP-Only Customer and/or an ODR-Only Customer. References in this

Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

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

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

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

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

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

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

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

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

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

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

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

Governance Participant is defined in the Participants Agreement.

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

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

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

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

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

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission

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

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

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

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

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

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

Hourly Real-Time Emergency Generation Resource Deviation means the difference between the Average Hourly Output of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction 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.

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.

HQ Interconnection Excess is the difference between the HQ Interconnection transfer limit as determined by the ISO and the Commission approved MW value of Hydro Quebec Interconnection Capability Credits.

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.

Hydro Quebec Interconnection Capability Credits are credits that are granted to a Market Participant or group of Market Participants in accordance with the ISO New England System Rules, where the value of such credits is determined in accordance with the ISO New England Manuals.

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, a DRP-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Payment (ICAP Payment) means the monthly payments made to ICAP Resources for installed capacity during the ICAP Transition Period.

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.

Installed Capacity Resource (ICAP Resource) means a resource that met the requirements to receive installed capacity payments during the ICAP Transition Period.

Installed Capacity Transition Period (ICAP Transition Period) is December 1, 2006 through May 31, 2010.

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.

Investment Grade Rating, for a Market (other than an FTR-Only Customer or DRP-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 New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

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

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

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

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

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

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

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

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

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

ITC Agreement is defined in Attachment M to the OATT.

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

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

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

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

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

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

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers 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, Demand Resource Critical 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 Resource is defined in Section III.6.1 of Market Rule 1.

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.

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.

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.

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

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 and/or a DRP-Only Customer and/or an ODR-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 Generation is the maximum generation output of a Real-Time 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 can deliver.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, measured at the retail delivery point of a Real-Time Demand Response Asset.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Minimum 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.

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

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

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

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

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

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

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

MUI is the market user interface.

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

MW is megawatt.

MWh is megawatt-hour.

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

NCPC Charge means the charges to Market Participants 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 Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

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.13.2.4(c) of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource (including any payment as an ICAP Resource pursuant to the market rules in effect prior to December 1, 2006 or any ICAP Payment during the ICAP Transition Period pursuant to the market rules in effect from December 1, 2006 through May 31, 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 England Control Area, for purposes of Section II of the Tariff, is the Control Area (as defined in Section II.1.11) 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 Control Area, for purposes of Section III of the Tariff, is the integrated electric power system to which a common automatic generation control scheme and various operating procedures are applied by or under the supervision of the ISO in order to: (i) match, at all times, the power output of the generators within the electric power system and capacity and energy purchased from entities outside the electric power system, with the load within the electric power system; (ii) maintain scheduled interchange with other interconnected systems, within the limits of Accepted Electric Industry Practice; (iii) maintain the frequency of the electric power system within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the NPCC and NERC; and (iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry Practice.

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

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 calculated in accordance with Section VII.B.2(i) of the ISO New England Financial Assurance Policy.

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.

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.

ODR-Only Customer is a Market Participant that registers with the ISO an Other Demand Resource (as defined in Section III.1 of this Tariff) and that does not participate in other markets or programs of the New England Markets, provided, however, that a DRP-Only Customer may also be an FTR-Only Customer and/or an DRP-Only Customer.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand 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.

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 Demand Resource (ODR) is an installation undertaken as part of a merchant, utility, or state-sponsored program, and may include Energy Efficiency, Load Management, and Distributed Generation projects that are installed after June 16, 2006, and that result in additional and verifiable reductions in end-use customer demand on the electricity network in the New England Control Area during specified ODR performance hours of the ICAP Transition Period.

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.

Out-of-Market Capacity is certain capacity that is counted in determining whether the Alternative Capacity Price Rule applies, as described in Section III.13.2.7.8 of Market Rule 1.

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, as remitting agent for the Covered Entities.

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.

Pivotal Supplier is defined in Section III.A.5.2.2 of Appendix A of Market Rule 1.

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.

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.E.8.

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 Load Zone or system-wide basis, and the ISO notifies the Market

Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours. Beginning on June 1, 2011, "Real-Time Demand Resource Dispatch Hours" shall be defined as 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 Critical Peak Demand Resources and 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 the hours, or portions thereof, when the ISO dispatches Real-Time Demand Response Resources in the Load Zone where a Demand Resource is located in response to Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours. Beginning on June 1, 2011, Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Demand Resource Forecast Peak Hours and 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 the output of one or more emergency generators 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 to curtail electric consumption. Real-Time Emergency Generation Resources would be dispatched by the ISO on a 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. Beginning on June 1, 2011, 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 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, 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 Accepted Electric Industry 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.

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.

Re-Offer Period is the period normally between 16:00 and 18:00 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.

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.

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.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer, a DRP-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 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.

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.

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.

SPD means the ISO's Scheduling, Pricing, and Dispatch software, as more fully described in Section III.A.5.5.3 of Appendix A of Market Rule 1.

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.

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.

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.

Submitted Offer is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

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 Margin is defined in Section III.A.5.2.2 of Appendix A 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 Restoration and Planning Service is the form of Ancillary Service described in Schedule 16 of the OATT. System Restoration and Planning Service is referred to as blackstart service.

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 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 Load Zone or, starting on June 1, 2011, 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 Load Zone or, starting on June 1, 2011, 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.

UCS is Unit Commitment Software as more fully defined in Section III.A.5.5.3 of Appendix A of Market Rule 1.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

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

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

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

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

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III.8 Demand Response Baselines

A Demand Response Baseline is calculated for any Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that requires a baseline on a daily basis using five-minute meter data.

8.1 Establishing the Initial Demand Response Baseline

The Demand Response Baseline for a new Real-Time Demand Response Asset or Real-Time Emergency Generation Asset (an asset with no previously computed Demand Response Baseline) shall be the simple average of meter data for the asset for each five-minute interval from the initial ten non-Demand Response Holiday weekdays. The initial ten non-Demand Response Holiday weekdays of meter data used to establish the Demand Response Baseline shall consist of the first ten consecutive non-Demand Response Holiday weekdays with a complete set of interval meter data. A Market Participant may not submit Demand Reduction Offers until the month following the initial establishment of a Demand Response Baseline for an asset.

8.2 Establishing the Demand Response Baseline for the Present Day

If, for a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

(a) the asset has been dispatched or audited in the present day pursuant to Section III.13, or;
(b) the Demand Reduction Offer associated with the asset is eligible in the Operating Day for payments pursuant to Section III.E.9, then:

the asset's Demand Response Baseline, in each five-minute interval, for the present day is equal to the Demand Response Baseline, in the same five-minute interval from the prior day.

8.3 Establishing the Demand Response Baseline for the Next Day

If, for a Real-time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

(a) the asset has not been dispatched or audited in the present day pursuant to Section III.13, or;

(b) the Demand Reduction Offer associated with the asset is not eligible in any hour of the Operating Day for payments pursuant to Section III.E.9, or;

(c) the Demand Reduction Offer associated with the asset is eligible in the Operating Day for payments pursuant to Section III.E.9 and more than seven of the prior 10 non-Demand Response Holiday weekdays have a Demand Response Baseline determined pursuant to Section III.8.2, then:

the asset's Demand Response Baseline in each five-minute interval, for the next day is calculated as the sum of 0.9 times the asset's Demand Response Baseline in the same five-minute interval from the prior day and 0.1 times the asset's meter data in the same five-minute interval in the present day.

8.4 Baseline Adjustment

8.4.1 Baseline Adjustment for Real-Time Demand Reductions from Assets Without Generation

For each day the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset pursuant to Section III.E.8.1, the ISO will calculate an adjustment factor equal to the average difference (MW) between the asset's actual metered demand and its Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load.

8.4.2 Baseline Adjustment for Real-Time Demand Reductions from Assets with Generation

For each day the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset pursuant to Section III.E.8.2, the ISO will calculate an adjustment factor equal to the average difference (MW) between the sum of the asset's actual metered demand and the output of all generators located behind the asset's retail delivery point in the same time intervals and the asset's Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load, plus the output of all generators located behind the asset's retail delivery point in the same time intervals as the asset's Maximum Load.

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset that is comprised of a Distributed Generation asset located behind the retail delivery point of an individual end-use customer facility, the asset's Demand Response Baseline shall not be subject to the baseline adjustment.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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EXHIBIT 1 MARKET IMPACT AND NCPC THRESHOLDS

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EXHIBIT 5 ISO NEW ENGLAND INC. CODE OF CONDUCT

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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

III.A.1.1. Mission Statement.

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

III.A.1.2. Structure and Oversight.

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

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

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III A.12.4 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

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

III.A.2. Functions of the Market Monitor

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

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

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.5.10 and Section III.A.7 of this ***Appendix A***). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

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

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

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

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

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlines in Sections III.A.14 and III.A.15 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.12 of this ***Appendix A***.

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

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.14 and/or III.A.15 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

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

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

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

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

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

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

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

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

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

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlines in Section III.A.14 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.14 and III.A.15 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

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

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.12 of this ***Appendix A***.

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

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

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

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

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

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.8 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.7 of this ***Appendix A.***

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

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

(i) Anti-competitive gaming of Resources;

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

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

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

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

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

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.12 of this ***Appendix A***. Monitoring under this Section III.A.2.3 (k) cannot serve as a basis for mitigation under III.A.8 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.2.5.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.7, or III.A.8. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

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

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

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

III.A.2.4.1.Purpose.

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

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

(a) *Imposing Mitigation*. To achieve the foregoing purpose and objectives, mitigation measures should only be imposed to remedy conduct that would substantially distort or impair the competitiveness of any of the markets administered by the ISO. Accordingly, and as more fully described in Sections III.A.5, III.A.8, and III.A.9 below, the ISO shall seek to impose mitigation measures only to remedy conduct that:

(i) is significantly inconsistent with competitive conduct as discussed below in Section III.A.2.4.2(b); and

(ii) would result in a change in one or more prices in the New England Markets or NCPC payments to a Market Participant beyond the thresholds defined in ***Exhibit 1***, Section III.A.5.3 or Section III.A.5.8 of this ***Appendix A***, as appropriate.

(b) *Conduct Inconsistent with a Competitive Market*. In general, the ISO shall consider a Market Participant's conduct to be inconsistent with competitive conduct if the conduct would (i) reduce the net revenue associated with the Resource, but for the effect of the conduct on market outcomes, or (ii) reduce the capability of the Transmission System resulting in a price impact in the New England Markets or NCPC payments in excess of either of the thresholds in ***Exhibit 1***, Section III.A.5.3 or Section III.A.5.8 of this ***Appendix A***, as appropriate.

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

III.A.2.4.3 Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4 Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this ***Appendix A***, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5 Duration of Mitigation Measures.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this ***Appendix A*** or in ***Appendix B*** to Market Rule 1.

III.A.3. Consultation Requirements

III.A.3.1. In General.

If through the application of an appropriate index or screen or other monitoring of market conditions, conduct is identified that (i) exceeds an applicable threshold, and (ii) has a material effect, as specified below, on one or more prices or NCPC payments in the New England Markets administered by the ISO, the Internal Market Monitor will take the steps set forth in this Section III.A.3:

III.A.3.1. Notice and Opportunity to Respond.

Before imposing mitigation for violation of general market thresholds (excluding thresholds regarding congestion mitigation)

(a) The Internal Market Monitor will, whenever practicable, contact the Market Participant engaging in the identified conduct to request an explanation of the conduct;

(b) If the explanation, if available, considered together with other information available to the Internal Market Monitor, indicates to the satisfaction of the Internal Market Monitor that the questioned conduct is consistent with competitive conduct as discussed above in Section III.A.2.4.2(b) no further action will be taken; and

(c) The Internal Market Monitor will consider any information a Market Participant submits, but is not required to delay mitigation while waiting for information.

III.A.3.1.2.Consideration of Information in All Cases.

In every case, the Internal Market Monitor will consider all available explanations of behavior that are based on a Market Participant's cost of providing any market product, including

(a) Any relevant opportunity costs,

(b) The need to shape bids and offers for a Limited Energy Resource to maximize the economic value from the Resource over time given the unique characteristics of the Resource, and

(c) any special price limitations applicable to dual-fuel resources.

III.A.3.1.3.Advance Consultation by Market Participant.

If a Market Participant anticipates submitting offers in a market administered by the Internal Market Monitor that will exceed the thresholds specified in Sections III.A.4, III.A.5, III.A.7, or III.A.8 for identifying conduct inconsistent with competition, the Market Participant may contact the Internal Market Monitor to provide an explanation of any legitimate basis for any such changes in the Market Participant's offers. If a Market Participant's explanation of the reasons for its bidding indicates to the satisfaction of the Internal Market Monitor that the questioned conduct is consistent with competitive conduct, no further action will be taken.

III.A.3.1.4. Market Participant Access to Its Reference Levels.

(a) The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's offers; the energy components will generally be available on a daily basis, but in all cases Reference Levels will be available upon request. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

(b) Upon request or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.5.6 for that Market Participant. If cost data or other information submitted by a Market Participant indicates to the satisfaction of the Internal Market Monitor that the

Reference Levels for that Market Participant should be changed, revised Reference Levels shall be determined, communicated to the Market Participant, and implemented, as soon as practicable.

III.A.4. Physical Withholding

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This Section defines thresholds used to identify possible instances of physical withholding. This Section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

III.A.4.2.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,

(b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,

(c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or

(d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.3. Thresholds for Identifying Physical Withholding.

III.A.4.3.1. Initial Thresholds.

Except as specified in subsection III.A.4.3.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

(a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;

(b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.3.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that is not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.3.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.3.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.4. Hourly Market Impact and NCPC Thresholds.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets or NCPC payments in excess of either of the thresholds in ***Exhibit 1***, or Section III.A.5.3.3, as appropriate.

III.A.5. Economic Withholding and Uneconomic Production

III.A.5.1. Purpose.

This Section addresses mitigation relating to economic withholding, uneconomic production and reliability commitment. If conduct is detected that exceeds one of more of the thresholds specified in Sections III.A.5.3 or III.A.5.4 and the Internal Market Monitor determines that there is a market impact to the extent required under Section III.A.5.5, the conduct shall be remedied by the prospective application of a Default Offer as described in Section III.A.5.7. If conduct is detected that fails the Commitment Offer Test in Section III.A.5.8.3 relating to reliability commitment mitigation, the conduct shall be remedied by the application of mitigation as described in Section III.A.5.8.4.

III.A.5.2. Applicability.

III.A.5.2.1. In General.

Only Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated in the Real-Time Energy Market. In the event a mitigation measure is imposed on a Supply Offer for a Resource pursuant to Section 5.8 of the ***Appendix A***, the Resource's NCPC payments shall not be mitigated under Section 5.7 for the same Operating Day.

III.A.5.2.1.1. Resources with Partial Capacity Supply Obligations.

Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding; notwithstanding the foregoing, the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of the block containing the Resource's Economic Minimum Limit and the highest block containing megawatts with a Capacity Supply Obligation;

(b) the entire offer block of a Resource shall be treated as having a Capacity Supply Obligation in any case where the block contains megawatts that are subject to a Capacity Supply Obligation;

(c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, by default the megawatts that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the megawatts that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five business days prior to the start of the month. Such a proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior; and

(d) Day-Ahead Energy Market mitigation measures will apply to all hours in the Day-Ahead Energy Market.

III.A.5.2.2. Pivotal Supplier.

A "Pivotal Supplier" shall mean, for each hour any Market Participant whose aggregate energy Supply Offers (up to and including Economic Max) for such hour are greater than the Supply Margin. The "Supply Margin" for an hour shall mean the total energy Supply Offers (up to and including Economic Max) for such hour, less total system load (as adjusted for net interchange with other Control Areas and including Operating Reserve). Prior to the Day-Ahead clearing process or the Real-Time hourly dispatch, the Internal Market Monitor shall calculate the Supply Margin and designate any Pivotal Suppliers and related generating Resources for each hour in the Day-Ahead Energy Market and the Real-Time Energy Market. In the Day-Ahead Energy Market, an ISO load forecast shall be used in making the above determination.

III.A.5.3. Thresholds for Identifying Economic Withholding.

III.A.5.3.1. General Thresholds.

The Internal Market Monitor shall investigate the reasons for and market impact of any offers from a Pivotal Supplier that exceed the following thresholds. Offers from a Pivotal Supplier exceeding these thresholds and market impact thresholds and for which no sufficient explanation has been provided, shall be mitigated to the Default Offer as determined in Section III.A.5.7.3.

(a) Energy Offer Price. A 300 % increase or an increase of $100/ MWh above the Reference Level, whichever is lower, but excluding offers under $25.

(b) Startup and No-load Offer Price. A 200 % increase above the Reference Level.

(c) Reserved.

(d) Time Based Offer Parameters. An increase greater than 2 hours in elements of a generating Resource's Offer Data that are expressed in time (e.g. minimum run time, minimum down time, cold start time, hot start time) or greater than six hours for any combination of such time-based Offer Data compared to the unit's Reference Levels.

(e) Offer Parameters Expressed Other than in Time or Dollars. A 100 % increase for Offer Data that are minimum values, or a 50 % decrease for Offer Data that are maximum values (including, but not limited to, ramp rates and maximum starts per day).

III.A.5.3.2. Reserved.

III.A.5.3.3. Additional Thresholds Applicable in Constrained Areas.

In addition to the thresholds set forth in Section III.A.5.3.1, for generating Resources located in a constrained area, the following thresholds shall be employed by the Internal Market Monitor to identify economic withholding that may warrant mitigation measures. Offers exceeding these conduct thresholds and market impact thresholds and for which no sufficient explanation has been provided, shall be mitigated to the Reference Level determined as specified in Section III.A.5.6.

(a) For Supply Offers for the Real-Time Energy Market: for intervals in which a generating Resource is dispatched for the purpose of relieving a transmission constraint above the level at which it otherwise would have been dispatched ("Constrained Hours"), the Internal Market Monitor shall assess the market impact of any Supply Offers (Section III.A.5.5.2(b)) that meet the following thresholds:

(i) Energy Offer price – an increase of $25 or 50%, whichever is lower, above the Reference Level; or

(ii) Start-up or no-load price – an increase of 25% above the Reference Level.

(b) For Supply Offers for the Day-Ahead Energy Market: for all Constrained Hours (as defined above) the Internal Market Monitor shall assess the market impact of any Supply Offers for the generating Resource that meet a threshold determined in accordance with the formula specified in subsection (a).

III.A.5.4. Threshold for Identifying Uneconomic Production.

In addition to the thresholds governing forms of economic withholding in Section III.A.5.3, the Internal Market Monitor will monitor for actions not consistent with competitive conduct, as defined in Section III.A.2.4.2(b), involving uneconomic production. The following thresholds may warrant the imposition of a mitigation measure as provided in Section III.A.5.7: (i) Energy scheduled at an LMP that is less than 20% of the applicable Reference Level and that causes transmission congestion; or (ii) Real-Time output from a Resource that exceeds 110% of the ISO's Dispatch Rate, and causes transmission congestion.

III.A.5.5. Hourly Market Impact and NCPC Thresholds

III.A.5.5.1. Initial Investigation.

Before imposing any mitigation measure as permitted in Section III.A.5.7, with regard to offers and bids identified in accordance with Sections III.A.5.3.1, III.A.5.3.3, and III.A.5.4, the Internal Market Monitor shall investigate the reasons for the change in accordance with the applicable provisions of Section III.A.3. If the offers and bids in question are not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the offers and bids in question would, if not mitigated, cause a material effect on the LMP at a Node, or clearing prices in the New England Markets or NCPC charges as provided in Sections III.A.5.5.2 and III.A.5.5.3.

III.A.5.5.2. Market Impact Thresholds.

Before a mitigation measure is imposed on offers exceeding the conduct thresholds, the Internal Market Monitor will determine whether there is an impact as follows:

(a) For offers exceeding the thresholds in Section III.A.5.3.1, a material effect is one in excess of either of the thresholds in ***Exhibit 1***, Section 1 or ***Exhibit 1***, Section 2 as applicable.

(b) For offers exceeding thresholds in Section III.A.5.3.3, a material effect is one in excess of the conduct threshold specified in Section III.A.5.3.3 above or NCPC payment thresholds as specified in ***Exhibit 1***, Section 2.

III.A.5.5.3. Calculation of Price Impact.

(a) When it has the capability to do so, the Internal Market Monitor shall determine the effect on prices in constrained areas as the difference between the LMP at the Resource node and the LMP at the Hub. When it has the capability to do so, the Internal Market Monitor shall determine the effect on prices in unconstrained areas by rerunning the ISO’s market settlement software (MSS) through the market operator interface (MOI). The Internal Market Monitor shall determine the effect on NCPC payments of questioned conduct by comparing NCPC payments calculated using actual offers to NCPC payment calculated using the default offer.

(b) When a determination in accordance with paragraph (a) above is not practicable, including, but not limited to when market operations are being performed in the back-up control center during an Emergency, the Internal Market Monitor shall manually determine the effect on prices or NCPC payments of questioned conduct. The price impact analysis will be performed to allow *ex ante* mitigation in the Day-Ahead Energy Market. *Ex ante* mitigation in the Real-Time Energy Market will be performed as soon as practicable.

(c) The Internal Market Monitor may set thresholds below which it need not apply the MSS and MOI if it is reasonable to conclude that the market impact thresholds are not likely to be violated.

(d) In constrained areas, if appropriate models are not available as the result of limitations in hardware, software, or other technical difficulties, the Internal Market Monitor will manually evaluate the impact to determine if it is at least as large as the threshold value. If that is not practicable, then either of the following will be deemed to be a violation of the market impact screen for a constrained area Resource exceeding a conduct threshold specified in Section III.A.5.3: (i) the scheduling of such Resource, or (ii) if the unit is not scheduled, a determination that the Reference Level for such Resource is less than the offer price of the marginal resource by more than the threshold specified in ***Exhibit 2***, Section 2.4, will be deemed to have violated the market impact screen.

III.A.5.6. Calculation of Resource Reference Levels.

III.A.5.6.1. Methods for Determining Reference Levels.

The Internal Market Monitor will calculate a reference price or, where an element of a bid or offer is not in dollars, the time-based or quantity level (any of which being referred to as a “Reference Level”) for each component of a generator’s bid on the basis of the following procedures:

(a) The Internal Market Monitor will calculate Reference Levels using the first of the following three procedures for which adequate information is available, with the understanding that, for dollar-based Supply Offer parameters, Reference Levels will be calculated using the third of the three procedures if the

Reference Levels calculated using the third procedure are greater than the Reference Levels calculated using either of the first two procedures.

(i) The lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation (excluding negative values) or bid components (hereinafter, a "Submitted Offer") in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource;

(ii) If that procedure is not applicable due to lack of data, then the mean of the LMP at the Resource's location during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours or load levels, adjusted for changes in fuel prices; or

(iii) A level negotiated with the Market Participant submitting the bid or bids at issue, and intended to reflect the Resource's marginal costs, provided such a level has been negotiated prior to the occurrence of the conduct being examined by the Internal Market Monitor, and provided that the Market Participant has provided data on the Resource's operating costs in accordance with specifications provided by the Internal Market Monitor. The Internal Market Monitor's determination of a generating unit's marginal costs shall include an assessment of the unit's incremental operating costs in accordance with the following formula, and such other factors or adjustments as the Internal Market Monitor shall reasonably determine to be appropriate based on such data supplied by the Market Participant or otherwise available to the Internal Market Monitor:

(heat rate * fuel costs) + (emissions rate * emissions allowance price) + other variable and operating maintenance costs

(b) Notwithstanding Section IIIA.5.6.1(a), for any Resource that has been flagged as VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market in the previous 90 days, if the ratio of (the sum of the operating hours for flagged days during the previous 90 days in which the number of Day-Ahead and Real-Time hours operated out of economic merit order exceed the number of Day-Ahead and Real-Time hours operated in economic merit order) divided by (the total number of Day-Ahead and Real-Time operating hours during the previous 90 days) is greater than or equal to 50 percent, then the Resource is not eligible for a

Reference Level as described in subsection (i) above and will receive a Reference Level as described in subsection (iii) above. For the purposes of this subsection:

(1) A flagged day is any day in which the Resource has been flagged as VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.

(2) Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared MWs greater than zero and hours in the Real-Time Energy Market for which a Resource has metered MWs greater than zero. For days for which Real-Time Energy Market metered MWs are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered MWs values will be used.

(3) Self-Scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

(4) The determination as to whether a Resource operated in economic merit order during an hour will be based on its incremental energy offer.

III.A.5.6.2 Insufficient Data.

If sufficient data does not exist to calculate a Reference Level as provided in Section III.A.5.6.1, the Internal Market Monitor may determine a Reference Level on the basis of:

(a) the estimated costs of the generating unit, taking into account appropriate input from the Market Participant; or

(b) an appropriate average of competitive bids of one or more similar generating units.

III.A.5.7. Mitigation Measures

III.A.5.7.1. Manual Review Prior to Mitigation.

The Internal Market Monitor will manually review a generating Resource's Reference Level before imposition of mitigation where practicable.

III.A.5.7.2. Conditions for Imposition of Mitigation Measures.

The Internal Market Monitor may impose a Default Offer as set forth in this Section III.A.5.7 if the following conditions have been met:

(a) A Submitted Offer exceeds an applicable threshold set forth in Sections III.A.5.3 and III.A.5.4 for an available Resource; and the conduct is not explained to the satisfaction of the Internal Market Monitor in accordance with Section III.A.3; and

(b) The market impact thresholds described in Section III.A.5.5 are exceeded.

III.A.5.7.3. Level of Default Offers.

A substitute mitigated offer (a "Default Offer") shall be designed to cause a Market Participant to offer as if it faced workable competition during a period when (i) the Market Participant does not face workable competition, and (ii) has responded to such condition by engaging in economic withholding. In designing and implementing Default Offers, the Internal Market Monitor shall seek to avoid causing a Resource to offer below its marginal cost.

III.A.5.7.4. Implementation.

(a) The Default Offer may establish a mitigated value for one or more components of the offer for a given Resource equal to a Reference Level for that component of the Resource's offer determined as specified in Section III.A.5.6.1.

(b) A Resource subject to a Default Offer shall be paid the LMP or other market clearing price applicable to the output from the Resource. Accordingly, a Default Offer shall not limit the price that a Resource may receive or pay unless the Default Offer determines the LMP or other market clearing price applicable to that Resource.

(c) Mitigation measures shall not be applied if the price effects of the measures would cause the average day-ahead energy price in the mitigated locations or zones to rise over the entire day.

(d) Any mitigation measure imposed under this Section III.A.5.7 will be in effect for the following duration:

(i) For mitigation requiring application of the impact test in Section III.A.5.5 above, mitigation measures shall be imposed from the first hour in which the impact test is met through the end of the Operating Day, or from the first hour in which the impact test is met through the end of the mitigated Resource's minimum run time, whichever is longer.

(ii) For mitigation not requiring application of the impact test in Section III.A.5.5 above, (a) mitigation of offer parameters expressed in dollars shall be imposed from the first hour in which the applicable conduct threshold is violated through the end of the Operating Day, or from the first hour in which the applicable conduct threshold is violated through the end of the mitigated Resource's minimum run time, whichever is longer, and (b) mitigation of offer parameters expressed other than in dollars will be in effect for the entire first Operating Day and, if the minimum run time of the Resource carries over to the second Operating Day, the entire second Operating Day.

(e) The posting of the Day-Ahead schedule, rebidding period and reliability commitment run may be delayed if necessary for the completion of mitigation procedures.

(f) Mitigation that does not affect the LMP or a clearing price in another ISO market may be applied in the settlement process.

III.A.5.8. Reliability Commitment Mitigation.

III.A.5.8.1. Applicability.

The mitigation measures prescribed in this Section III.A.5.8 shall apply to Supply Offers for Resources that are committed to provide or Resources that are required to remain online to provide:

(a) outside of the Day-Ahead Energy Market, local first contingency protection or local second contingency protections;

(b) voltage support or voltage control; or

(c) Special Constraint Resource Service.

III.A.5.8.2. Duration

Any mitigation measure imposed pursuant to this Section III.A.5.8 will be in effect for the follow duration.

(a) *Resources with a Minimum Run Time Carryover*. For a Resource with a minimum run time that carries over from one Operating Day to the following Operating Day, mitigation will be in effect for the entire first Operating Day through the minimum run time of the Resource. Notwithstanding the foregoing, if the resource is selected for one of the reasons, in Section III.A.5.8.1 after the start of the Operation Day, then mitigation will be in effect from the time of such selection.

(b) *Resources without a Minimum Run Time Carryover*. For a Resource with a minimum run time that does not carry over from one Operating Day to the following Operating Day, mitigation will be in effect for the entire Operating Day, or if the decision to mitigate is made after the start of the Operating Day, then from the time at which the decision is made through the remainder of the Operating Day.

III.A.5.8.3. Commitment Offer Test

All Supply Offer parameters expressed in monetary values will be tested by application of the following formula.

(Low Load Cost at Offer – Low Load Cost at Mitigation Value)<Commitment Cost Threshold

Where,

Commitment Cost Threshold = the lower of (0.1 times Low Load Cost at Mitigation Value) or ($80 times the Resource’s Economic Maximum).

Low Load Cost = the cost of running the Resource at Economic Minimum calculated using the Following formula:

(Cold Start-Up Fee + (No Load Fee * minimum run time) + (Price of Energy at Economic Min * Economic Min* minimum run time))

Low Load Cost at Offer = Low Load Cost calculated with unmitigated dollar-based values of the Supply Offer.

Low Load Cost at Mitigation Value = Low Load Cost calculated with dollar-Based Mitigation Values of the Supply Offer.

Price of Energy at Economic Min = The price in the Supply Offer for energy at the Resource's Economic Min.

Mitigation Value = Max [Reference Level, cost-based Reference Level as determined in Section III.A.5.6.1 (b)(iii)]

If the (Low Load Cost at Offer – Low Load Cost at Mitigation Value) is equal to or greater than the Commitment Cost Threshold, a failure of the Commitment Offer Test will be deemed to have occurred.

If a Resource's combined minimum run time and minimum down time exceed 24 hours, then the Commitment Offer Test will use the greater of 24 hours or the Resource's minimum run time for the minimum run time.

III.A.5.8.4 Consequence of Failing Commitment Offer Test.

If a Resource fails the Commitment Offer Test and on the basis of its unmitigated Supply Offer would receive NCPC Credits, the mitigation values for (a) Start-Up Fee (cold, intermediate, or hot as appropriate) (b) No-Load Fee and (c) energy price shall be used for purposes of calculating NCPC Credits for the Resource in the Day-Ahead Energy Market and Real-Time Energy Market under Appendix F of this Market Rule 1.

III.A.5.9. Determination of Offer Competitiveness During Shortage Event

The Internal Market Monitor shall evaluate the competitiveness of the Supply Offer of each resource with a Capacity Supply Obligation that is off-line during a Shortage Event, as described below. The evaluation for competitiveness shall be performed on Supply Offers in the Day-Ahead Energy Market and Supply Offers made during the re-offer period. A determination of non-competitiveness for a Day-Ahead Energy Market Supply Offer or a Supply Offer made during the re-offer period which affects an hour shall constitute a finding of non-competitiveness for that hour.

(a) The thresholds used for evaluation shall be the general thresholds in Section III.A.5.3.1 unless the constrained area mitigation thresholds apply in the Day-Ahead Energy Market or Real-Time Energy Market and the resource under evaluation could have fully or partially relieved the constraint during the applicable Shortage Event. If the constrained area mitigation thresholds apply, then the energy price Supply Offer parameter and the Start-Up Fee and No-Load Fee parameters shall be evaluated for competitiveness using the thresholds in Section III.A.5.3.3.

(b) If the value of any of the following Supply Offer parameters for a resource exceeds the relevant thresholds for an hour, all MW for the resource for the hour shall be non-competitive:

(i) The Start-Up Fee and No-Load Fee;

(ii) Each time-based Supply Offer parameter;

(iii) The energy price Supply Offer parameter up to and including the Economic Minimum Limit.

(c) If none of the parameters evaluated for competitiveness pursuant to Section III.A.5.9(b) above are non-competitive for an hour, then the energy price parameter for each incremental Supply Offer block above the resource's Economic Minimum Limit shall be evaluated for competitiveness using the thresholds identified in Section III.A.5.9(a) above, in order of lowest energy price to highest energy price. If any Supply Offer block is non-competitive, then that block and all blocks above it shall be non-competitive, and all blocks below it shall be competitive.

III.A.5.10. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.6. [Reserved]

III.A.7. Demand Bids

The Internal Market Monitor will monitor Demand Resources as outlined below:

(a) LMPs in the Day-Ahead and Real-Time Energy Markets shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.

(b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.8. Mitigation of Increment Offers and Decrement Bids

III.A.8.1 Purpose.

The provisions of this Section III.A.8 specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement

Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and ISO New England Manuals.

III.A.8.2. Implementation.

III.A.8.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead and Real-Time LMPs, measured as:

$$(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.8.2.2. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead and Real-Time markets, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

(i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.

(ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.

(iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead and Real-Time Energy Markets.

III.A.8.3. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in Market Rule 1.

III.A.8.4. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.9. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.9.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor’s review and the consequences that will result from the Internal Market Monitor’s determination following such review.

(a) Section III.13.1.1.2.6 Review by Internal Market Monitor of Offers from New Generating Capacity Resources Below 0.75 Times CONE.

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

(c) Section III.13.1.2.3.2 Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

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

(e) Section III.13.1.7. Internal Market Monitor Review of Offers and Bids.

III.A.9.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.9.3 Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.9.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Participant in accordance with Section III.A.3 of this ***Appendix A***. The Internal

Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.9.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer ***Appendix B*** in accordance with the provisions thereof.

III.A.9.6 Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.

Article 5 of the Form of Cost-of-Service Agreement in Appendix I to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.10. Request for Additional Cost Recovery.

III.A.10.1 Filing Right.

If either (a) as a result of mitigation applied to a Resource under this Appendix A for all or part of one or more Operating Days, or (b) in the absence of mitigation, despite having submitted a Supply Offer at the energy offer cap specified in Section III.1.10.1A(d) of Market Rule 1, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for those Operating Days, the Market Participant may, within **sixty** days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.

III.A.10.2 Contents of Filing.

Any Section 205 filing made pursuant to this Section III.A.10 shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource for the Operating Days exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource for the Operating Days exceeded the costs as reflected in the Supply Offer at the energy offer cap; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.10.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.10.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.10 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.10.2(i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.10 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III.A.10.

III.A.10.4 Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this Section III.A.10, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in Question.

III.A.11. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.11.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in ***Appendix D*** to Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.
- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.11.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral (as defined in ***Appendix D***) shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.12. Reporting

III.A.12.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this ***Appendix A***, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

(a) the opportunity costs associated with Demand Reduction Offers;
(b) the accuracy of Demand Response Baselines;
(c) the method used to achieve a demand reduction, and;
(d) the accuracy of reported demand levels.

III.A.12.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.12.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.12.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more State public utility commission (s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A***.

III.A.12.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISOs website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.12.3 of this ***Appendix A***.

III.A.12.3. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.12.4. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of ***Appendix A***. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

(i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.

(ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.

(iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.

(iv) Review and assessment of the effectiveness of ***Appendix A*** and the administration of ***Appendix A*** by the Internal Market Monitor for consistency and compliance with the terms of ***Appendix A.***

(v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.12.5. Other Internal Market Monitor or External Market Monitor Communications with Government Agencies.

III.A.12.5.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the

Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.12.5.2 Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;

(b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;

(c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.12.5.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.12.2.2.

III.A.12.6. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). With respect to state regulatory bodies and state attorneys general ("authorized state agencies"), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement action of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten business days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information..

III.A.13. Ethical Conduct Standards

III.A.13.1 Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as ***Exhibit 5***.

III.A.13.2. Additional Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.13.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.13.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.13.3. Additional Standards Application to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 13 of Appendix A, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standards(s) shall control.

III.A.14. Protocols on Referrals to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) The name(s) of and, if possible, the contact information for, the entity (ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);

(2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;

(3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

(4) The specific act(s) or conduct that allegedly constituted the Market Violation;

(5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

(6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;

(7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.15. Protocol on Referral to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) A detailed narrative describing the perceived market design flaw(s);

(2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;

(3) The rule or tariff change (s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;

(4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

SECTION III

MARKET RULE 1

APPENDIX E

DEMAND RESPONSE

APPENDIX E

DEMAND RESPONSE

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APPENDIX E
DEMAND RESPONSE

1. Demand Response Registration

A Market Participant may register a Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis to provide demand reductions during hours ending 0800 through 1800 on non-Demand Response Holiday weekdays subject to the following conditions:

(a) the asset is able to produce at least 100 kW of demand reduction, and;

(b) the metering and communication equipment associated with the asset meets the requirements specified in Section III.E.2.

1.1 Registration Parameters

During the registration process, Market Participants must submit the following information for each Real-Time Demand Response Asset:

(a) Maximum Interruptible Capacity;

(b) Maximum Load, and;

(c) Maximum Generation, for Real-Time Demand Response Assets that are comprised of Distributed Generation.

1.2 Restrictions on Real-Time Demand Response Asset Registration

A Market Participant may not register and must retire if previously registered a Real-Time Demand Response Asset that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

A Market Participant may not register an existing Generator Asset as a Real-Time Demand Response Asset for the purpose of submitting Demand Reduction Offers.

2. Metering and Communication

2.1 Interval Metering and Telemetry Requirements

The actual metered demand of each individual end-use customer facility that comprises a Real-Time Demand Response Asset must be measured using interval meters located at the individual end-use customer's retail delivery point and shall be reported to the ISO at an interval of five minutes. Actual metered demand submitted to the ISO shall not include average avoided peak distribution losses. Each generator located behind an individual end-use customer's retail delivery point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.

Interval meters required pursuant to Section III.E.2.1 must meet the following requirements:

(a) the interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes or less;

(b) if the interval meter is the same meter used by the distribution company for billing purposes, the meter is a revenue-quality meter that is accurate within ± 0.5%, and;

(c) if the interval meter is not the same meter used by the distribution company for billing purposes, the interval meter is either a revenue-quality meter that is accurate within ± 0.5% or a non-revenue-quality meter with an overall accuracy of ± 2.0%. For each non-revenue-quality meter used, the Market Participant must, during the registration process, submit certification from the meter manufacturer that the interval meter being used meets the ± 2.0% accuracy threshold, and shall specify accuracy for the following parameters:

i. current measurement;

ii. voltage measurement;

iii. A/D conversion, and;

iv. calibration.

2.2 Meter Testing

All interval meters must be periodically tested and calibrated.

Market Participants must conduct periodic meter data validation checks.

Market Participants must repair or replace meters that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters and meter data communication systems.

2.3 Auditing

The ISO may, for a Real-Time Demand Response Asset, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and measurement equipment, and witness the demand reduction activities of any facility associated with the asset.

Market Participants must make retail billing meter data from the Host Participant for the facilities associated with a Real-Time Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing, and certifying the metering, data recording and measurement equipment of Real-Time Demand Response Assets.

2.4 Communication/Telemetry

Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facilities comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area.

For Real-Time Demand Response Assets whose demand reductions are not achieved by Distributed Generation but where there is a generator located behind the retail delivery point, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of all generation.

For Real-Time Demand Response Assets whose demand reductions are achieved by Distributed Generation, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of Distributed Generation associated with the Real-Time Demand Response Asset.

3. Demand Reduction Offers

3.1 Required Demand Reduction Offer Parameters

Market Participants must submit a Demand Reduction Offer for each Real-Time Demand Response Asset that meets the requirements of this section in order to be eligible for a demand reduction payment.

A Demand Reduction Offer must be equal to or greater than the Demand Reduction Threshold Price in effect on the day the Demand Reduction Offer is made.

Demand Reduction Offers reflect the amount of demand reduction offered at the retail delivery point excluding transmission and distribution losses.

A Demand Reduction Offer shall consist of a single offer price in $/MWh (less than or equal to $1000/MWh) and a single demand reduction amount (in MW to the nearest 0.1 MW) that shall apply to hours ending 0800 through 1800 in the Operating Day.

A Market Participant may submit a single Demand Reduction Offer for each of its Real-Time Demand Response Assets for each Operating Day that is a non-Demand Response Holiday weekday.

Demand Reduction Offers for the following Operating Day must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the Operating Day and may not be changed thereafter.

The minimum Demand Reduction Offer amount for each Real-Time Demand Response Asset is 100 kW.

The maximum Demand Reduction Offer amount for each Real-Time Demand Response Asset cannot exceed the asset's Maximum Interruptible Capacity.

3.2 Optional Demand Reduction Offer Parameters

A Demand Reduction Offer may specify a minimum interruption duration of one to four hours. If a Market Participant does not specify a minimum interruption duration in its Demand Reduction Offer, the minimum interruption duration shall be one hour.

A Demand Reduction Offer may specify a curtailment initiation price (in $ per interruption). If a Market Participant does not specify a curtailment initiation price, the curtailment initiation price shall be $0.

A Demand Reduction Offer must meet the following minimum and maximum price requirements:

(a) The offer price not including the curtailment initiation price shall be greater than or equal to the Demand Reduction Threshold Price; and

(b) The offer cost of the Demand Reduction Offer, which shall include the curtailment initiation price, shall be less than or equal to $1000/MWh. The offer cost shall be computed as follows: offer cost = offer price + [curtailment initiation price/(minimum interruption duration x bid amount (MW))].

4. Day-Ahead Clearing, Scheduling and Notification

Demand Reduction Offers are cleared after the Day-Ahead Energy Market results are determined. Demand Reduction Offers are cleared by comparing the Demand Reduction Offer to the hourly Day-Ahead LMPs for the Load Zone in which the Real-Time Demand Response Asset is located. A Demand Reduction Offer associated with a Real-Time Demand Response Asset will clear in one or more hours of the Operating Day if the sum of the hourly Day-Ahead LMP times the Demand Reduction Offer amount in the cleared hours of the Operating Day is greater than or equal to the sum of the curtailment initiation price for the Operating Day and the sum of the Demand Reduction Offer price times the Demand Reduction Offer amount in the cleared hours of the Operating Day.

The ISO will provide Market Participants with demand curtailment schedules for Real-Time Demand Response Assets based on cleared Demand Reduction Offers.

The demand curtailment schedule shall reflect demand reductions (MW) at the Real-Time Demand Response Asset's retail delivery point.

5. Real-Time Scheduling of Demand Reductions

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for the next Operating Day pursuant to Section III.E.4. If a Market Participant's Demand Reduction Offer is not cleared Day-Ahead to reduce demand in an hourly time interval for the next Operating Day, the Market Participant may initiate a Real-Time demand reduction by reducing demand when the offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which a Real-Time Demand Response Asset is located.

A Market Participant will not receive a Dispatch Instruction in Real-Time for a Real-Time Demand Response Asset.

5.1 Requirements for Demand Reductions of 5 MW and Above

A Market Participant with a Real-Time Demand Response Asset that has submitted a Demand Reduction Offer for the Operating Day, must request permission from the ISO prior to reducing demand in an amount greater than or equal to 5 MW during a 60 minute period, unless the asset was dispatched or audited pursuant to Section III.13. Permission must be requested not less than 15 minutes and not greater than 60 minutes before the start of the demand reduction. The ISO may approve or deny the requested interruption based on the impact of the interruption on system reliability.

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data for the same month of the previous year. The ISO may adjust the offer data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

i. Each generator and import offer block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

ii. An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer block.

iii. A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

iv. A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from demand response exceeds the cost to load associated with compensating demand response.

v. The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} \times \frac{FPI_c}{FPI_h}$$

where FPI_h is the Forward Reserve Fuel Index for the same month of the previous year, and FPI_c is the Forward Reserve Fuel Index for the current month.

The ISO will post the resulting Demand Reduction Threshold Price on its website in advance of the Demand Reduction Threshold Price's effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Real-Time Demand Response Assets located anywhere within the New England Control Area.

7. Demand Response Baselines

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8 prior to submitting a Demand Reduction Offer for a Real-Time Demand Response Asset.

A Market Participant shall take no actions to establish a Demand Response Baseline or affect a Demand Response Baseline adjustment that results in a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers absent demand reduction payments.

For Real-Time Demand Response Assets comprised of Distributed Generation, a Market Participant shall take no actions to establish a Demand Response Baseline that results in a Demand Response Baseline that reduces the expected output levels of its generation absent demand reduction payments.

8. Real-Time Demand Reduction Obligations

8.1 Real-Time Demand Reduction of Assets Without Generation

The Real-Time demand reduction amount of a Real-Time Demand Response Asset is equal to the difference between its Demand Response Baseline adjusted pursuant to Section III.8.4 and the asset's Real-Time metered demand, during the intervals that the Real-Time Demand Response Asset was scheduled Day-Ahead by the ISO to reduce demand or was otherwise eligible to receive payment for a demand reduction in Real-Time. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered demand is greater than its adjusted Demand Response Baseline.

8.2 Real-Time Demand Reduction of Assets With Generation

To the extent a generator is located behind the retail delivery point of an individual end-use customer facility that comprises a Real-Time Demand Response Asset, the metered output of the generator in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline. The Real-Time demand reduction amount achieved by the individual end-use customer facility that comprises a Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval minus the sum of the metered demand measured at the retail delivery point and the output of all of the generators located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of all of the generators is greater than its adjusted Demand Response Baseline.

If a Real-Time Demand Response Asset is comprised of a Distributed Generation asset located behind the retail delivery point of an individual end-use customer facility, the interval metered output of the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be used to determine its Demand Response Baseline. The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be equal to the asset's incremental output in each five-minute interval relative to its Demand Response Baseline in the same intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered output is less than its Demand Response Baseline.

8.3 Treatment of Net Supply

If the metered amount measured at the retail delivery point reflects net energy supply during intervals in which Real-Time Demand Response Assets and/or Real-Time Emergency Generation Assets behind the retail delivery point had positive Real-Time demand reductions, then the amount of net energy supplied in an interval with a positive Real-Time demand reduction shall be subtracted from the Real-Time demand reduction amount in the same interval of each Real-Time Demand Response Asset and/or Real-Time

Emergency Generation Asset behind that retail delivery point on a *pro rata* basis. The adjustment for net energy supply shall not result in a negative Real-Time demand reduction amount.

8.4 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Real-Time Demand Response Asset is equal to its Real-Time demand reduction amount adjusted for net supply (limited to 200% of the associated Demand Reduction Offer amount) multiplied by one plus the percent average avoided peak distribution losses.

9. Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Real-Time Demand Response Asset will be paid for its Day-Ahead Demand – Reduction Obligation multiplied by the Day-Ahead LMP for the Load Zone within which the Real-Time Demand Response Asset is located.

9.2 Real-Time Settlement

9.2.1. Real-Time Demand Response Assets with Cleared Demand Reduction Offers

A Market Participant with a Real-Time Demand Response Asset will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the final hourly Real-Time LMP for the Load Zone within which the Real-Time Demand Response Asset is located. The payment for the amount by which the Real-Time Demand Reduction Obligation exceeds the Day-Ahead Demand Reduction Obligation in an hour shall be set to zero if the provisional Real-Time LMP for that hour is less than the Demand Reduction Threshold Price.

A Market Participant will not be charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E.5.1.

9.2.2. Real-Time Demand Response Assets without Cleared Demand Reduction Offers

If the Demand Reduction Offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which the Real-Time Demand Response Asset is located, the Market Participant will be paid the final hourly Real-Time LMP multiplied by its Real-Time Demand Reduction Obligation.

A Market Participant will not be charged pursuant to Section III.E.9.2.2 if:

(a) a Demand Reduction Offer does not clear Day-Ahead pursuant to Section III.E.4, and;

(b) the Real-Time Demand Response Asset produces a negative Real-Time demand reduction amount.

A Market Participant will not be paid for a Real-Time Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E.5.1.

9.3 Cost Allocation

Payments and charges pursuant to this section will be allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes or incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

10. Average Distribution Losses

For purposes of Section III.E, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

ATTACHMENT D

ISO New England Information Policy

Table of Contents

Introduction

The ISO New England Information Policy establishes rules and guidelines regarding the appropriate disclosure of all information received, created and distributed in connection with the operation of and participation in the markets administered by ISO New England Inc. (the "ISO"). The Policy allows stakeholder committees, task forces and working groups (collectively, "Stakeholder Committees"), the ISO, and Governance Participants to share information with the benefit of a common understanding regarding how that information will be used and how appropriate confidentiality will be maintained. This Policy document consists of three sections. Section 1 highlights the Policy's intent and objectives. Section 2 discusses confidentiality issues. Finally, Section 3 specifies what types of information are available to whom. This Section, in its entirety, is intended to replace the Information Classification Document appendix of the formerly adopted Policy (March 5, 1999 version).

Changes to the Information Policy will be made in accordance with Section 11.3 of the Participants Agreement.

Section 1 -Policy Intent & Objectives

The intent of this Policy is twofold. First, to allow Governance Participants to provide certain *Confidential Information* to the ISO, Stakeholder Committees, and other Governance Participants with the benefit of a common understanding regarding how that information will be used and how appropriate confidentiality will be maintained. Second, to provide the ISO, Stakeholder Committees and Governance Participants clear guidance regarding the appropriate disclosure of all information received, created or distributed in connection with the operation of and participation in the markets administered by the ISO. This Policy will pertain to all information held by Stakeholder Committees or the ISO, or furnished by or to a Governance Participant as a result of its participation in the markets administered by the ISO, whether it is publicly available or strictly confidential.

In order to meet the general obligations of the Transmission, Markets and Services Tariff, the Participants Agreement, the Transmission Operating Agreement, the Rates Design and Funds Disbursement Agreement, and other documents that affect the rates, terms, and conditions of service, including all exhibits and attachments to the listed documents (hereafter collectively referred to as the "Filed Documents"), each Governance Participant is required to furnish to and may be entitled to receive from Stakeholder Committees or the ISO certain information, some of which may be considered confidential, commercially sensitive, and/or strategic in nature. This information is used by the ISO, Stakeholder Committees or Governance Participants, as appropriate, for the following purposes, among others:

1. To operate the bulk power supply system on a day-to-day basis.

2. To administer the Open Access Transmission Tariff.

3. To administer the New England electricity markets, including the bidding process, billing system and settlement function.

4. To monitor the competitiveness and efficiency of the market and Governance Participants' compliance with relevant market rules and procedures.

5. To assess and plan for the long term reliability and adequacy of the New England bulk power supply system.

6. To provide reports and data as required or appropriate to the various user groups as described in Section 3 of this document.

It is recognized that the successful operation of the New England Control Area is highly dependent on access to certain types of information. The high degree of bulk power supply reliability and adequacy that customers of Governance Participants have become accustomed to expect is, to some degree, a result of Governance Participants' willingness to provide the necessary information. It is only with the ISO's continued access to the information necessary to perform its duties described above that the benefits obtained from bulk power supply pooling can continue.

This Information Policy will:

1. Recognize that protecting the confidentiality of certain information is important to the Governance Participants.

2. Recognize that the ISO and each Governance Participant have the responsibility to protect the confidentiality of such information.

3. Provide procedures and guidelines to the ISO, Stakeholder Committees and Governance Participants regarding the handling, publication and distribution of all information.

This Information Policy is intended to comport with the obligation of the ISO, Stakeholder Committees and the Governance Participants to comply fully with the antitrust laws and the information access and disclosure provisions of the standards of conduct promulgated by the Federal Energy Regulatory Commission in 18 C.F.R. § 37.4 (the "Codes of Conduct"). The Information Policy is expressly intended both: **(1)** to protect against the disclosure of *Confidential Information* that could facilitate anticompetitive conduct prohibited by the antitrust laws and **(2)** to distribute information to the extent and in a manner consistent with preserving the competitiveness and efficiency of the New England electric markets and the reliability of the bulk power system.

No modifications or additions shall be made to Section 3 of this document that result in limiting the disclosure of *Confidential Information* by Governance Participants that are municipalities, state or municipal agencies, or other public agencies unless such information contains trade secrets or commercial or financial information that has otherwise been kept confidential.

Section 2 -Confidentiality Issues

2.0 Confidentiality

Confidential Information furnished by a Governance Participant to Stakeholder Committees and/or the ISO shall, for the purposes of this Information Policy, be considered the sole and exclusive property of such Governance Participant (the "Furnishing Governance Participant"). To the extent that such *Confidential Information* is furnished to Stakeholder Committees and/or the ISO it shall be used solely to perform their obligations under the NEPOOL Agreement and the ISO Agreement. No Governance Participant shall be entitled to receive from the ISO and/or Stakeholder Committees any *Confidential Information* furnished by another Governance Participant under the NEPOOL Agreement unless the Furnishing Governance Participant has provided the relevant Stakeholder Committees and/or the ISO written authorization for such release. The disclosure of *Confidential Information* in accordance with this Information Policy shall not be used by any Governance Participant as a basis for a claim that the Governance Participant furnishing such *Confidential Information* has waived, relinquished, or reduced in any way the Furnishing Governance Participant's rights to prevent further disclosure of such *Confidential Information*.

The Governance Participants recognize that one of the purposes of the ISO is to prepare analyses, forecasts and reports for the general public, reliability councils, regulators and other user groups.

Preparation of such analyses, forecasts and reports requires the use of Governance Participants' information, some of which may be *Confidential Information* of an individual Governance Participant.

Governance Participants' obligations to provide information to the ISO or Stakeholder Committees arise under the Filed Documents. Nothing in this Information Policy is intended to expand or alter those obligations. Nothing in this Information Policy requires the ISO to release information to Stakeholder Committees, Governance Participants or any other person if the ISO in good faith believes that the release of such information would violate any applicable law or regulation, including the Codes of Conduct, or the terms of any valid confidentiality agreement or have a material adverse effect on the competitiveness or efficiency of the markets administered by the ISO.

2.1 Confidential Information

The following information will be considered *Confidential Information* for the purposes of this Policy:

(a) Information that **(i)** is furnished by a Governance Participant (the "Furnishing Governance Participant") to the ISO, Stakeholder Committees or another Governance Participant, **(ii)** constitutes trade secrets or commercial or financial information, the disclosure of which would harm the Furnishing Governance Participant or prejudice the position of that Governance Participant in the New England electricity markets, and **(iii)** has been designated in writing by the Furnishing Governance Participant as confidential or proprietary either in the document which provided such information, in the transmittal materials accompanying such information, or in a separate document which identifies the information with sufficient specificity and clarity so that the entity receiving such information has been made aware that the Furnishing Governance Participant seeks confidential treatment for such information.

(b) Information that **(i)** is furnished by the ISO to a Governance Participant or a Stakeholder Committee, **(ii)** constitutes trade secrets or commercial or financial information the disclosure of which would have an adverse effect on the ability of the ISO to perform its responsibilities under the ISO Agreement, and **(iii)** has been designated in writing by the ISO as confidential or proprietary either in the document which provided such information, in transmittal materials accompanying such information, or in a separate document which identifies the information with sufficient specificity and clarity so that the entity receiving such information has been made aware that the ISO seeks confidential treatment for such information. In addition, information that is furnished by the ISO to a Governance Participant or a Stakeholder Committee relating to the job status or performance or terms of employment of any ISO employee ("ISO Employment Information") shall be *Confidential Information*.

(c) Information that **(i)** is furnished by a non-Governance Participant that takes part in a demand response program operated by the ISO (a "DR Information Provider") to the ISO, Stakeholder Committees or any Governance Participant in connection with the demand response program, **(ii)** constitutes trade secrets or commercial or financial information, the disclosure of which would harm the DR Information Provider or prejudice the position of the DR Information Provider in the demand response program, and **(iii)** has been designated in writing by the DR Information Provider as confidential or proprietary either in the document which provided such information, in the transmittal materials accompanying such information, or in a separate document that identifies the information with sufficient specificity and clarity so that the entity receiving such information has been made aware that the DR Information Provider seeks confidential treatment for such information.

(d) Information that **(i)** is furnished by a non-Governance Participant acting as a Project Sponsor to the ISO, Stakeholder Committees or any Governance Participant in connection with the Forward Capacity Market, **(ii)** constitutes trade secrets or commercial or financial information, the disclosure of which would harm the Project Sponsor or prejudice the position of the Project Sponsor in the Forward Capacity Market, and **(iii)** has been designated in writing by the Project Sponsor as confidential or proprietary either in the document which provided such information, in the transmittal materials accompanying such information, or in a separate document that identifies the information with sufficient specificity and clarity so that the entity receiving such information has been made aware that the Project Sponsor seeks confidential treatment for such information.

(e) Information disclosed to satisfy the "Minimum Criteria for Market Participation" set forth in Section II.A of the ISO New England Financial Assurance Policy that (i) is furnished by a Furnishing Governance Participant to the ISO, Stakeholder Committees or another Governance Participant or is furnished by the ISO to a Governance Participant or a Stakeholder Committee, (ii) constitutes sensitive or non-public information concerning the Participant or identifying or concerning the Principals of a Participant, the disclosure of which could harm the Furnishing Governance Participant or its Principals, and (iii) has been designated in writing by the Furnishing Governance Participant or by the ISO as confidential either in the document which provided such information, in the transmittal materials accompanying such information, or in a separate document which identifies the information with sufficient specificity and clarity so that the entity receiving such information has been made aware that the Furnishing Governance Participant or the ISO seeks confidential treatment for such information.

(f) Any report, compilation or communication produced by the ISO or a Stakeholder Committee that contains information described in Clause (a), (b), (c), (d) or (e) above and allows for the specific identification of the Furnishing Governance Participant or the DR Information Provider.

Confidential Information shall exclude information if and to the extent such information **(1)** is or becomes generally available to the public without any party violating any obligation of secrecy relating to the information disclosed, or **(2)** is received by a Governance Participant in good faith from a third party who discloses such information on a non-confidential basis without violating any obligation of secrecy relating to the information disclosed, or **(3)** is defined as "Public Information," in Section 3, or **(4)** can be shown by the recipient's prior records to have been already known to the recipient other than through disclosure by a third party which would not be subject to exclusion based on (2) above.

Confidential Information, as defined in this Section 2.1, may be provided to specific user groups entitled to information pursuant to Sections (a) through (i) of Section 3.0. Section 3.0 is not intended, however, to add to or vary the criteria specified above. Otherwise, except as specifically provided herein, no other distribution or disclosure of *Confidential Information* shall be permitted by the ISO, Stakeholder Committees or Governance Participants.

2.2 Treatment of Confidential Information

The Governance Participants shall take reasonable measures to assure that all of their employees, representatives, or agents who by virtue of their participation on, or as an alternate on, a Stakeholder Committee have access to *Confidential Information* of another entity that furnished the information, including, as appropriate, a Furnishing Governance Participant, a DR Information Provider or the ISO (the "Furnishing Entity") (1) do not disclose such *Confidential Information* to any other employee, representative, or agent of the same Governance Participant or any other person except as permitted under this Section 2.2 and (2) use such information solely for the purpose of satisfying that person's responsibilities on the Stakeholder Committee. Each Governance Participant shall, upon request by the Participants Committee, provide assurance that the terms of this Section 2.2 are complied with. Any Governance Participant that has furnished *Confidential Information* to Stakeholder Committees may require each recipient to return all or any portion of the *Confidential Information* once it is no longer needed by such recipient to fulfill its responsibilities under the Filed Documents.

Notwithstanding the foregoing, the ISO, the Participants Committee or any Governance Participant may disclose *Confidential Information* of another Governance Participant or the ISO only: **(1)** if such disclosure is permitted in writing by the Furnishing Entity, DR Information Provider or the ISO, as the case may be, or **(2)** if disclosure is required by order of a court or regulatory agency of competent jurisdiction or dispute resolution pursuant to the Filed Documents, or **(3)** as otherwise specifically permitted by this Policy. Any entity subject to this Information Policy shall provide prompt written notice to the Furnishing Entity if that entity either is compelled by order of a court or regulatory agency of competent jurisdiction to disclose, or receives a request seeking to compel disclosure of, *Confidential Information* for which it is not the Furnishing Entity. Further, in recognition that certain Governance Participants are subject to public records and open meeting laws and that certain other demands may be placed on Governance Participants to disclose *Confidential Information*, a recipient of *Confidential Information* of another Governance Participant or the ISO may disclose such *Confidential Information* if and to the extent required by law or requested in writing pursuant to a public records demand or other legal discovery process, provided in either event that the disclosing Governance Participant gives the Furnishing Governance Participant or the ISO prompt written notice of the circumstances that may require such disclosure in time so that the Furnishing Governance Participant or the ISO has a reasonable opportunity to seek a protective order to prevent disclosure.

Notwithstanding anything to the contrary contained in this Section 2.2, the ISO, the Participants Committee, or any Governance Participant may disclose *Confidential Information* to an alternate dispute resolution ("ADR") neutral in an ADR proceeding required or permitted by any New England market rule, including Appendix A, "Market Monitoring, Reporting and Market Power Mitigation," and Appendix B, "Imposition of Sanctions," to Market Rule 1, or to an arbitrator in an arbitration proceeding under the Filed Documents. In addition, the ISO or any Governance Participant may disclose *Confidential Information* to a Dispute Representative as defined in, and permitted by, Section 5 of the Billing Policy. Any such ADR neutral, arbitrator or Dispute Representative must agree to be bound by this Information Policy.

Notwithstanding anything to the contrary in this Information Policy, resource-specific information contained in the data fields of the Forward Capacity Tracking System, but not information provided to the

ISO as separate attachments via the Forward Capacity Tracking System, will be shared with subsequent Lead Market Participants or Project Sponsors for that resource.

Notwithstanding anything to the contrary in the ISO New England Information Policy, the ISO, the Participants Committee, or any Governance Participant may disclose *Confidential Information* as required or permitted to satisfy the "Minimum Criteria for Market Participation" set forth in Section II.A of the ISO New England Financial Assurance Policy.

2.3 Disclosure of Information Regarding Defaulting Governance Participants

Notwithstanding any provision herein to the contrary, the information for release to Governance Participants identified in this Section shall no longer be deemed "*Confidential Information*" pursuant to the Information Policy. For any Governance Participant that is the subject of a voluntary or involuntary bankruptcy petition or has sought relief under bankruptcy or insolvency laws, or that has otherwise defaulted under its arrangements with the ISO, which default is not, or the ISO reasonably concludes will not be, cured within five days of the date of the default, in the case of a Payment Default (as defined in the Billing Policy) or within ten days of the date of its default in the case of any other defaults, the following information with respect to that Governance Participant's obligations shall be disclosed by the ISO to each member and alternate on the Participants Committee, each Governance Participant's billing contacts, appropriate Stakeholder Committee(s) designated by the Participants Committee, and appropriate state regulatory or judiciary authority:

> For the 60 calendar day period prior to the date of the bankruptcy, insolvency petition or other default (the "Default Date") and from the Default Date forward until such time as the Governance Participant cures the default: **(i)** the type and available amount of financial assurance in place; **(ii)** any notification provided by such Governance Participant pursuant to the Financial Assurance Policy and/or Billing Policy to the ISO of a material change in its financial status; **(iii)** any change in the type or available amount of financial assurance provided by such Governance Participant; **(iv)** whether such Governance Participant has defaulted on its payment obligations under the Billing Policy, the amount of any such default, the date of the default, and when or whether the default is cured; **(v)** whether such Governance Participant has defaulted on its obligations under the Financial Assurance Policy, the amount of any such default, the date of the default, and when or whether the default is cured; **(vi)** where the financial assurance provided by such Governance Participant is a bond, whether the ISO has provided notice of default to the surety and whether the surety has given notice of termination of the bond or otherwise disclaimed or refused to honor or

delayed in honoring its obligations under the bond, and the response of the ISO to any such notice; **(vii)** whether such Governance Participant is a net seller or purchaser in the New England Markets; **(viii)** the amount of such Governance Participant's purchases in the New England Markets; and **(ix)** whether such Governance Participant owns a registered Load Asset.

If a Governance Participant is suspended from the New England Markets, the ISO immediately shall send notice of such suspension to each of the members and alternates on the Participants Committee, the energy regulatory agencies in each of the New England states and the Federal Energy Regulatory Commission. Said notice shall identify the specific date and time of the suspension.

2.4 Breach of Confidential Information Obligations

The Governance Participants and the ISO acknowledge that remedies at law for any breach of the obligations under this Section 2 would be inadequate and agree that, in enforcing this Section 2, in addition to any other remedies provided at law:

(a) A Furnishing Governance Participant may, at its option, take one or both of the following actions: **(i)** apply to any court of equity having jurisdiction for an injunction restraining the ISO, any Stakeholder Committee or any Governance Participant from an actual or threatened violation of this Section 2 relating to *Confidential Information* provided by such Furnishing Governance Participant and **(ii)** submit such actual or threatened violation to arbitration in accordance with the procedure provided in Section 17.3 of the Participants Agreement and Section I of the Transmission, Markets and Services Tariff.

(b) The ISO may, at its option, take one or both of the following actions: **(i)** apply to any court of equity having jurisdiction for an injunction restraining a Governance Participant or any Stakeholder Committee from an actual or threatened violation of this Section 2 relating to *Confidential Information* and **(ii)** submit such actual or threatened violation to arbitration in accordance with the procedure provided in Section 17.3 of the Participants Agreement and Section I of the Transmission, Markets and Services Tariff.

(c) The Participants Committee may, at its option, take one or both of the following actions: **(i)** apply to any court of equity having jurisdiction for an injunction restraining the ISO from an actual or threatened violation of this Section 2 relating to *Confidential Information* and **(ii)** submit such actual or threatened violation to arbitration in accordance with the procedure provided in Section

17.3 of the Participants Agreement and Section I of the Transmission, Markets and Services Tariff.

Section 3 -Information Access

3.0 Information Access

(a) Public Information

This information includes:

- Public record filings with regulatory agencies. (Some examples include, but are not limited to, ISO Budget Data required for ISO Tariff Filings; and data associated with the Open Access Transmission Tariff.)

- Data posted on the Open Access Same-Time Information System ("OASIS"). (Some examples include, but are not limited to, Transmission Facilities Information including System Inventory; New Applications; Scheduling Information, Real Time Tie Line Use and Surplus Availability; Aggregate MW of generation operating out of merit (for transmission, reliability, and VAR) by Reliability Region (these Regions will be defined by the ISO, such that no *Confidential* or Strategic Information is released), Real Time Operating Reserve Availability and curtailment or interruption of External Transactions.)

- Information and/or reports that are required to be filed with the Federal Energy Regulatory Commission ("FERC") (unless specifically required to be filed on a confidential basis). (For example, the Filed Documents.)

- Public Generator Information including System Inventory and New Applications. (Some examples include, but are not limited to, Capacity, Energy, Loads & Transmission (CELT) Report; and 18.4 Applications.)

- Public Market Information includes any items required to be made public by **(i)** the Filed Documents; **(ii)** other relevant documents, including without limitation the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England system and administration of the Market and the Filed Documents; and **(iii)** the items listed in Aggregate Market

Results, as posted under "Market Information" on the ISO website pursuant to this Information Policy. (Some examples include, but are not limited to, aggregate Market requirements and settlements; Clearing Prices; Locational Marginal Prices; lists of load zones, nodes and hubs; Emergency Energy notices; market monitoring input assumptions and threshold values; Financial Transmission Rights modeling and auction results; Auction Revenue Rights modeling and auction results; information relating to the Load Response Program; ICAP Market Schedules and UCAP auction results.)

- In addition, the System Operator shall publish each month's bid and offer information for all markets on its website on the first day of the fourth calendar month following the month during which the applicable demand bids and supply offers were in effect (e.g., bid and offer data for January would be released on May 1), provided that the information is presented in a manner that does not reveal the specific load or supply asset, its owners, or the name of the entity making the bid or offer, but that allows the tracking of each individual entity's bids and offers over time.

- Market test information including any information equivalent to Public Market Information derived from test programs for new markets or market software or simulations of proposed market improvement (includes any and all information necessary for evaluation of the impacts of a proposed new market or an improvement to an existing market, such as cost-shifting impacts and price impacts under certain conditions).

- Long-term system planning and operations information consisting of load forecasts, transmission models (including power flow, short circuit and stability models and their related base cases and contingency files), transfer limits used for planning purposes, Installed Capacity Requirements and Governance Participants and non-Governance Participants proposed generation. This information does not include near-term transmission models or transfer limits within New England that are developed as part of system operations or real-time information from the control room energy management system.

- Public Reports required by the Filed Documents (including, but not limited to, evaluation of procedures for determination of Locational Marginal Prices as well as the awarding Financial Transmission Rights and associated Congestion Costs and Transmission Congestion Credits).

- Public Market Monitoring Information including, but not limited to, public reports by the Independent Market Advisor required by the Market Rules (includes the ISO's time and expenses in pursuing sanctionable behavior on a case-by-case basis and periodic reports of sanctions imposed and the sanctionable behavior upon which such sanctions were imposed, provided that the information is presented in a manner that does not allow for the identification of the Governance Participants by name or provide a manner for identifying such Governance Participants, except as otherwise provided in the Filed Documents).

- Any other information that is not *Confidential Information* that the ISO determines is appropriate for public dissemination because it will improve system reliability, the efficiency of the markets or public understanding of the New England system and the operations of the ISO.

This data may be made available to the public at large. (Fees may be applicable to cover process and handling expenses.) [This information corresponds to the MIS security rule "PB" Public.]

(b) Non-Public Transmission Information

This information includes:

- Information and/or reports that are filed with the North American Electric Reliability Council (NERC). (Some examples include, but are not limited to, all NPCC data, see examples below.)

- Information and/or reports that are filed with the Northeast Power Coordinating Council (NPCC).

- Real-time system operations information, which is not posted on the OASIS, including but not limited to detailed operations data. (Some examples include, but are not limited to, real-time transmission line flows, real-time transfer limits, and real-time voltages.)

- Information relating to specific Generating facilities, which is required by transmission personnel to ensure the reliable operation of the New England bulk power system. (Some examples include, but are not limited to, detailed Generator operating characteristics; and dynamic swing recorder plots.)

- Transmission Operating Guides. (Some examples include, but are not limited to, guides for operation of Special Protection Systems; and transmission operations related to Stability Limits.)

- Information related to system restoration efforts. (Some examples include, but are not limited to, ISO and Governance Participants' detailed Power System Restoration Plans.)

This information may be made available to Reliability Councils and all Governance Participants' Transmission Personnel. The release of relevant transmission outage information to affected generators, to the extent required or desired for coordination of transmission and generation outages, shall be governed by the processes available for such coordination (OP3 or any successor or similar document), by the Codes of Conduct and by other applicable FERC regulation. There is no direct correlation to the MIS Security Rules and there is currently no specific transmission information distributed via the MIS.

(c) Governance Participant Specific Data

This information includes:

- Data not yet posted on the OASIS. (Some examples include, but are not limited to, Interface Transmission Service Schedules Lists.)

- *Confidential Information*, as defined in Section 2.1 of this Policy, for which this Governance participant, or an Agent thereof, has the right to receive the data. (Some examples include, but are not limited to, Product Obligation; and Load.)

- Invoice and Settlement Data. (Some examples include, but are not limited to, Governance Participant Phase I/II Hourly Transfer Capability Allocations; Electrical Load, Adjusted Net Interchange, Obligation, Entitlement, Charges, and Payments for each market.)

[This data may be made available to active users or agents of the specified Governance Participant. This information corresponds to the MIS security rule "SM" Settlement Rule.]

(d) Asset Specific Information – Near Real-Time

This information includes:

- Near real-time information related to the particular asset. (Some examples include, but are not limited to, Generation Levels (MW); Designations (MW); Automatic Generation Control Status, Operating Limits, Response Rates, unit forecast and operation information, and Real Time Status of External

Contract Sales and/or Purchases for which a Governance Participant has a contract on file with the ISO.)

This data may be made available to those Governance Participants, or Agents thereof, who are joint Owners and/or Entitlement Holders in the Asset. [This information corresponds to the MIS security rules “OS” Ownership Rule, “RS” Responsible Party Rule and an Entitlement Holder Rule, currently not identified in the MIS security rules. As applicable, this data may also be made available to a Governance Participant who is a contractual party to external or internal bilateral contracts for the specified Asset, which corresponds to the MIS security rule “TH” Transaction Holder Rule.] The release of relevant generation outage information to affected transmission owners, to the extent required or desired for coordination of transmission and generation outages, shall be governed by the processes available for such coordination (OP3 or any successor or similar document), by the Codes of Conduct and by other applicable FERC regulation.

(e) Asset Specific Information – Forecast and post-Settlement

This information includes:

- Unit Forecast information relating to a particular Asset, which is necessary to determine the projected operation of particular Generators. (Some examples include, but are not limited to, Start Time; Generation; and Shut-Down Time.)

- Information relating to a particular Asset, which is necessary to determine the accuracy of Settlement. (Some examples include, but are not limited to, High Operating Limit; Generation; Ownership Share; and Duration on Automatic Generation Control.)

- Governance Participant input data. (Some examples include, but are not limited to, generation input data; and records of deficient performance.)

- Capability Responsibility (CR) data and calculations, for those specific Generating facilities for which a Governance Participant(s) has an ownership interest. (Some examples include, but are not limited to, Unit Capability Demonstrations and Audits; and Seasonal Claimed Capability.)

- All information, with the exception of bids, offers and meter data, necessary to verify Settlement data. (Some examples include, but are not limited to, Response Rate data; and Minimum Run-Time data.)

This data may be made available to those Governance Participants, or Agents thereof, who are joint Owners and/or Entitlement Holders in the Asset. [This information corresponds to the MIS security rules "OS" Ownership Rule, "RS" Responsible Party Rule and an Entitlement Holder Rule, currently not identified in the MIS security rules.] The release of relevant generation outage information to affected transmission owners, to the extent required or desired for coordination of transmission and generation outages, shall be governed by the processes available for such coordination (OP3 or any successor or similar document), by the Codes of Conduct and by other applicable FERC regulation.

(f) Meter, Bid and Offer Data

This information includes:

- *Confidential Information* submitted as input to the Market System. Bid and offer data may be made available to any Governance Participant with a Generation Ownership Share, or Agent thereof, for a specified Asset. [This information corresponds to the MIS security rules "RS" Responsible Party Rule.]

- Meter data may be made available to the Assigned Meter Reader for a specified Asset. There is no direct correlation to the MIS Security Rules and there is currently no specific MIS distribution of meter data. However, meter data may be manually distributed to the Host Participant whose unmetered load is calculated based on said meter data.

(g) Reliability, Operations and Area Control Information

(i) External Control Center Information

This information includes:

- All System Operations or Planning Information that relates to the particular external Control Center. (Some examples include, but are not limited to, transmission interface transfers and limits within the external control center area; and Inter-Area Emergency Assistance available, used for Planning purposes, under OP-4 conditions.)

- Information that is required to assure the reliable operation of the interconnected bulk power system. (Some examples include, but are not limited to, all information deemed necessary in the event of OP

4 implementation; and, under non-OP-4 system conditions, information related to Inter-Area flow control.)

- Inter-area Transmission Operating Guides that relate to the particular external control area. (Some examples include, but are not limited to, PV-20 Cross Trip SPS – available to New York; and Phase I Runback SPS – available to Hydro Quebec.)

- *Confidential Information* (under signature of confidentiality agreements that provide rights to Governance Participants equivalent to those granted in this Information Policy to notice of and opportunity to defend against any release of their *Confidential Information*) and non-confidential information may be shared among Control Areas for the purposes of increasing markets coordination, including elimination of seams, increasing market efficiency and study purposes of the interconnected bulk power system. (Some examples include, but are not limited to, ISO operations and markets information, including market monitoring information, provided that market monitoring information shall only be shared with independent market operators or independent market monitors and only in connection with particular investigations affecting regional markets.)

There is no direct correlation to the MIS Security Rules and there is no specific MIS distribution of External Control Center Information. This information is not available to Governance Participants, a subset thereof, or the Public at large, but is typically communicated by the ISO Operations (Control Room/Forecast Office) or Planning Department directly to External Control Center personnel.

(ii) Internal (Satellites) Control Center Information

This information includes:

- All System Operations or Planning Information. (Some examples include, but are not limited to, detailed system models; and transmission element data as detailed on the NX-9 forms.)

- Information relating to specific Generating facilities that is needed to assure the reliable operation of the New England Control Area. (Some examples include, but are not limited to, Generator constraints, including the reason for such constraint; and detailed Generator unit commitment.)

- Transmission Operating Guides. (Some examples include, but are not limited to, guides for operation of Special Protection Systems; and transmission operations related to Stability Limits.)

- New England and Satellite System Restoration Plans. (Some examples include, but are not limited to, the ISO, Satellite and Governance Participants' detailed Power System Restoration Plans.)

There is no direct correlation to the MIS Security Rules and there is no specific MIS distribution of Internal (Satellite) Control Center Information. This information is not available to Governance Participants, a subset thereof, or the Public at large, but is typically communicated by the ISO Operations (Control Room/Forecast Office) directly to Satellite personnel.

(h) Load Response Provider Information

This information is asset-specific Confidential Information, including:

- Retail customer information;
- Customer data;
- Load profiles, and;
- Demand response information provided at the request of the Internal Market Monitor pursuant to Section III.A.12.

Information relating to retail customers, customer data and load profiles is subject to certain state law restrictions and is not available to Governance Participants, a subset thereof, or the public at large, but is typically communicated by the ISO Operations (Control Room/Forecast Office) directly to Load Response Provider personnel.

(i) ISO New England Information

This information includes:

- Any Governance Participant or Asset specific information as requested by the ISO, which will be maintained in accordance with this Policy. (Some examples include, but are not limited to, all Governance Participant and Asset specific information, which is available to the ISO.)

- Any ISO Employment Information and ISO Administrative Information not specifically listed in other categories.

ISO personnel, Consultants, Counsel, and Board Members may have access to any information defined in the categories listed above. This information corresponds to the MIS security rule "ISO" ISO New England.

All *Confidential Information*, as defined in Section 2.1 of this Policy, will only be distributed in accordance with this Policy.

All other data, which is not specifically defined and is not *Confidential Information*, may be released at the discretion of the ISO in accordance with the procedures set forth in Sections 3.1, 3.2 and 3.3 hereto.

(j) Critical Energy Infrastructure Information ("CEII")

This information includes:

- Information designated by a Governance Participant or the ISO as CEII, which is defined by FERC as "specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that: (1) relates details about the production, generation, transportation, transmission, or distribution of energy; (2) could be useful to a person in planning an attack on critical infrastructure; (3) is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552 (2000); and (4) does not simply give the general location of the critical infrastructure."

- Reports, summaries, compilations, analyses, notes or other information which contain such information.

Access to CEII shall be granted by the ISO in accordance with the CEII disclosure processes posted on its website and, in the event that the CEII also falls within a category of information (including *Confidential Information*) described herein, in accordance with this Information Policy. Governance Participants shall treat CEII as if it were *Confidential Information*, notwithstanding any other provision of this Information Policy, and additionally shall maintain CEII in a secure place.

3.1 Information Requests

(a) Requesting Entities

As used in this Section 3.1, the term "Requesting Entity" shall mean any entity (other than the FERC or an Authorized Person, as defined in Section 3.3 of this Information Policy) that requests information from the ISO.

(b) Public Information

If a Requesting Entity requests that the ISO publish Public Information (as defined in Section 3.0(a) of this Information Policy) that is not currently published by the ISO, the ISO may after consultation with the Participants Committee or its designated subcommittee or working group defer or deny such request if the ISO determines that publication of such data is not feasible at the time of such request due to resource limitations, including, without limitation, available software.

(c) Non-Public Information

(i) A Requesting Entity that desires to make a formal request for information that is not Public Information from the ISO, the resolution of which request shall be appealable under Section 3.1(e)(v) of this Information Policy, shall submit a formal written request to the ISO in the manner set forth in Section 3.1(d) below (a "Formal Information Request") for such information.

(ii) Requests for information from Requesting Entities to the ISO other than Formal Information Requests need not be in writing.

(iii) Any request for information from the FERC or from an Authorized Person (as defined in Section 3.3 of this Information Policy) shall be addressed according to the procedures set forth in Section 3.2 and Section 3.3 of this Information Policy, respectively.

(d) Form of Request; Tracking

(i) Any Formal Information Request shall be directed to the point of contact designated by the ISO to handle such requests (the "ISO Information Contact"). The ISO shall post contact information for the ISO Information Contact on the ISO website.

(ii) A Formal Information Request shall be in writing, which shall include electronic communications addressed to the ISO Information Contact, and shall: (a) describe with particularity the information sought; (b) provide a description of the purpose of the information request; (c) state the time period for which such information is requested; (d) specifically designate such request as a Formal Information Request and make reference to Section 3.1(d)(ii) of the Information Policy; and (e) provide contact information for the person to whom the response to such Formal Information Request is to be directed.

(iii) The ISO Information Contact shall track all Formal Information Requests and provide a report indicating the nature of each request and the response to such request to the Markets Committee on a monthly basis.

(e) Timing and Notice

(i) The ISO Information Contact normally shall notify all affected Furnishing Entities within five (5) business days after receiving a Formal Information Request.

(ii) The ISO Information Contact normally shall provide the Requesting Entity with a response (an "Initial Response") within fifteen (15) business days after receiving the Formal Information Request (the "Request Date"). The Initial Response shall indicate either (A) that the ISO has made a decision on the Formal Information Request in accordance with Section 3.1(f)(i) below, in which case it shall describe such decision, or (B) that the ISO was unable to reach a decision, and will be consulting with the Participants Committee in accordance with Section 3.1(f)(ii) below.

(iii) If the Initial Response indicates that the ISO is further consulting with the Participants Committee, the ISO Information Contact normally shall provide the Requesting Entity with a follow-up response (a "Follow-Up Response") the earlier of ten (10) business days after a recommendation by the Participants Committee as set forth in Section 3.1(f)(ii) below or sixty (60) days following the Request Date, which response shall indicate either (A) that the ISO has made a decision on the Formal Information Request in accordance with Section 3.1(f)(ii) below, in which case it shall describe such decision, or (B) that the ISO has failed to make a decision with respect to the Formal Information Request, in which case such request shall be deemed denied.

(iv) The ISO Information Contact shall provide the Furnishing Entity(ies) with copies of any Initial Response or Follow-Up Response provided in response to a Formal Information Request on the same day that such responses are provided to the Requesting Entity. In addition, the ISO Information Contact shall provide the Furnishing Entity(ies) with at least ten (10) business days prior written notice of any release of *Confidential Information* or Strategic Information relating to such Furnishing Entity (whether such release is on the ISO's own initiative, in response to a Formal Information Request, or otherwise), which written notice shall inform such Furnishing Entity(ies) of its right to dispute such release under Section 3.1(e)(v) of the Information Policy.

(v) The Requesting Entity shall have the right to appeal any Initial Response that contains a decision with respect to a Formal Information Request and any Follow-Up Response. Any affected Furnishing Entity shall have the right to appeal any Initial Response or Follow-Up Response that contains a decision with respect to a Formal Information Request and any decision by the ISO to release *Confidential Information* or Strategic Information (whether such release is on the ISO's own initiative, in response to a Formal Information Request, or otherwise). The Participants Committee shall have the right to appeal any Initial Response that contains a decision with respect to a Formal Information Request. Notice of any appeal shall be provided contemporaneously to the Participants Committee and the ISO Information Contact.

(vi) Any appeal of the ISO's actions under this Section 3.1 with respect to a Formal Information Request shall be subject to binding arbitration with FERC's Alternative Dispute Resolution Service, as further described in 18 C.F.R. §§ 385.604, 385.605. The ISO and the disputing entity(ies) shall use reasonable efforts to insure that an arbitrator is selected and a hearing is scheduled within thirty (30) days of the ISO receiving notice of an appeal. Unless otherwise agreed by all parties, the duration of any arbitration hearing will be limited to one day. The arbitrator's decision shall be binding on the respective parties; provided, however, that any of the respective parties to the arbitrator's decision shall be entitled to appeal the arbitrator's decision directly to FERC.

(vii) Suitable forms of notice and/or communications pursuant to this subsection shall include, but not be limited to, electronic communications.

(f) Consideration of Requests

(i) After receiving a Formal Information Request, the ISO shall first determine whether (X) the information requested is information described in Sections (a) through (i) of Section 3.0 and (Y) the Requesting Entity is a member of a user group specifically entitled to receive such information pursuant to Sections (a) through (i) of Section 3.0. If the ISO determines that the Requesting Entity is not entitled to receive the requested information pursuant to Sections (a) through (i) of Section 3.0, the ISO shall then determine if the requested information is *Confidential Information* or Strategic Information. The ISO may consult with the Independent Market Advisor, NEPOOL Counsel, the Furnishing Entity(ies), and/or the Participants Committee (as provided in Section 3.1(d)) during the process of making this determination.

(A) If the ISO determines that the information is *Confidential Information*, the ISO Information Contact will refer the request to the Furnishing Entity(ies) and the ISO will not release the requested information unless it is directed to do so by the Furnishing Entity(ies) or ordered to do so by a court or regulatory authority with jurisdiction over such matters. If the Furnishing Entity(ies) directs the ISO to release the requested information, the ISO will next determine whether the requested information is Strategic Information as set forth in Section 3.1(c)(i)(B) below. The Furnishing Entity(ies) shall bear any costs reasonably incurred by the ISO in opposing the issuance of such an order requiring disclosure of the Furnishing Entity(ies)' *Confidential Information*. Notwithstanding the foregoing, upon the request of a regulatory agency, other than FERC or its staff, having appropriate jurisdiction and subject to an appropriate confidentiality order entered under such agency's procedures sufficient to preserve the confidential nature of the information submitted, and with advance notice to the Furnishing Entity(ies), the ISO Information Contact may submit *Confidential Information* to such agency.

(B) If the information requested is Strategic Information, the ISO shall determine whether to release the requested information, in consultation with the Independent Market Advisor, NEPOOL Counsel and/or the Furnishing Entity(ies), as the ISO deems appropriate. If the ISO releases such information, it will do so by making the information public.

(C) If the information requested is neither *Confidential Information* nor Strategic Information, the ISO shall determine whether to release the requested information; provided that the Participants Committee, acting on the recommendation of an appropriate Stakeholder Committee, may request the ISO to release the requested information.

(ii) If, after consultation with the Independent Market Advisor, NEPOOL Counsel and/or the Furnishing Entity, as appropriate, the ISO cannot, in its good faith judgment, determine the classification status of requested information or otherwise believes that a Formal Information Request raises policy questions that should be determined by the Governance Participants, then the following procedure shall apply:

(A) The ISO shall refer the request to the Participants Committee with its recommendation for action.

(B) The Participants Committee, acting on recommendation of a subcommittee or working group, as appropriate, may approve of or suggest modifications to the recommendation of the ISO. If the Participants Committee approves the ISO's recommendation, or if the ISO accepts the Participants Committee's suggested modifications, the Participants Committee's decision shall determine the response to the Formal Information Request; provided, however, that, to the extent that the information requested is found to be *Confidential Information*, the ISO shall continue to maintain the confidentiality of such information in accordance with the terms of this Information Policy.

(g) Release of Information; Prioritization of Formal Information Requests

(i) The ISO shall reasonably attempt to comply with any Formal Information Request that has been granted within thirty (30) days of the Initial Response or Follow-Up Response informing the Requesting Entity that its request has been granted. The ISO may condition the release of any information to a Requesting Entity upon payment of the ISO's reasonable cost to identify and prepare such information.

(ii) If the ISO does not have the resources available to comply with all outstanding Formal Information Requests within the time provided in clause (i) above, the ISO will consult with the Participants Committee or its designated subcommittee or working group to determine how such Formal Information Requests should be prioritized.

(h) Definition of Strategic Information

For purposes of this Policy, Strategic Information means any information, except Public Information, that would affect a Governance Participant's bid or offer strategy in the New England electric markets including information affecting the offer price for or cost of operation of a resource, the capacity or availability of a resource, or any other offer parameter for a resource.

Strategic Information includes *Confidential Information* supplied by Governance Participants to the extent such information would affect a Governance Participant's bid or offer strategy such as, for example:

- All offer prices and parameters for particular resources including bid blocks and times.

- Cost information regarding operation of one or more resources if and to the extent supplied to the ISO.

- Information regarding fuel availability for thermal resources or impoundment levels for hydroelectric facilities.

- Information regarding transmission outages, not otherwise made public, for scheduled maintenance or otherwise that affects the availability of certain generating resources.

Strategic Information may also include information calculated or produced by the ISO such as:

- Aggregate prices and quantities offered that are derived through the unit commitment process.

- Information regarding which resources will run or have run during any particular market settlement period.

- Information derived through the unit commitment process or the market settlement system as to units that run out of merit.

- Information regarding the existence or location of certain short-term transmission constraints.

No Strategic Information that is *Confidential Information* will be released except in compliance with the provisions of this Information Policy regarding *Confidential Information*.

3.2 Disclosure to FERC

If the FERC or its staff, during the course of an investigation or otherwise, requests information from the ISO that is *Confidential Information* or CEII, the ISO shall provide the requested information to the FERC or its staff, within the time provided for in the request for information. In providing *Confidential Information* to FERC or its staff, the ISO shall, consistent with 18 C.F.R §§ 1b.20 and 388.112, request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure. The ISO shall notify any affected Furnishing Entity(ies) (1) when it is notified by FERC or its staff, that a request for disclosure of *Confidential Information* has been received at which time the ISO and the affected Furnishing Entity(ies) may respond before such information would be made public; and (2) when it is notified by FERC or its staff that a decision to disclose *Confidential Information* has been made, at which time the ISO and the affected Furnishing Entity(ies) may respond before such information would be made public. In providing CEII to FERC or its staff, the ISO shall, consistent with 18 CFR § 388.112, request that the information be treated as CEII by the FERC and its staff.

3.3 Disclosure to Authorized Persons

(a) Definitions

For purposes of this Section 3.3, the following terms shall have the meanings set forth below:

"Affected Governance Participant" shall mean a Governance Participant, which, as a result of its Participation in the markets administered by the ISO, provided Confidential Market Information to the ISO, which Confidential Market Information is requested by or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

"Authorized Commission" shall mean a State public utility commission within the geographic limits of the New England Control Area that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State.

"Authorized Person" shall mean a person who has executed a Non-Disclosure Agreement, and is authorized in writing by an Authorized Commission to receive and discuss Confidential Market Information. Authorized Persons may include attorneys representing an Authorized Commission, consultants and/or contractors directly employed by an Authorized Commission, provided; however, that consultants or contractors may not initiate requests for Confidential Market Information from the ISO or the IMMU.

"Confidential Market Information" shall mean *Confidential Information* consisting of market data relating to the markets administered by the ISO, including data supplied by Governance Participants and aggregate data regularly compiled by the ISO. Confidential Market Information shall not include the following categories of information without excluding any objective market data associated with them that would otherwise be provided under the first sentence of this definition: (i) draft versions of reports and analyses, (ii) internal ISO documents not related to market data, (iii) attorney-client communications, (iv) attorney work-product privileged information, (v) communications about Confidential Market Information between an Affected Governance Participant and the ISO/IMMU, except to the extent that the communications become part of final written reports or final written analyses by the ISO/IMMU, (vi) communications between an Affected Governance Participant and the ISO made on a confidential basis as part of a settlement proceeding or negotiation; and (vii) information provided to the ISO on a confidential basis as part of an Alternative Dispute Resolution proceeding.

"Information Request" shall mean a written request, in accordance with the terms of this Section 3.3 for disclosure of Confidential Market Information pursuant to Section 3.3 of this Information Policy.

"Non-Disclosure Agreement" shall mean an agreement between an Authorized Person and the ISO pursuant to Section 3.3 of this Information Policy, the form of which is appended to this Information Policy (Appendix A), wherein the Authorized Person is given access to otherwise restricted Confidential Market Information, for the benefit of their respective Authorized Commission.

"State Certification" shall mean the Certification of an Authorized Commission, pursuant to Section 3.3 of this Information Policy, the form of which is appended to this Information Policy (Appendix B), wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

"Third Party Request" shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of Confidential Market Information provided to the Authorized Person or Authorized Commission by the ISO or IMMU. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for Confidential Market

Information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

(b) Procedures

(i) Notwithstanding anything in this section to the contrary, the ISO and/or the External Market Monitor shall disclose Confidential Market Information, otherwise required to be maintained in confidence pursuant to this Information Policy, to an Authorized Person under the following conditions:

(1) The Authorized Person has executed a Non-Disclosure Agreement with the ISO representing and warranting that he or she: (i) is an Authorized Person; (ii) is duly authorized to enter into and perform the obligations of the Non-Disclosure Agreement; (iii) has adequate procedures to protect against the release of any Confidential Market Information received, (iv) is familiar with, and will comply with any applicable procedures of the Authorized Commission which the Authorized Person represents, (v) covenants and agrees on behalf of himself or herself not to disclose the Confidential Market Information and to deny any Third Party Requests and defend against any legal process which seeks the release of any Confidential Market Information received in contravention of the terms of the Non-Disclosure Agreement, and (vi) is not in breach of any Non-Disclosure Agreement entered into with the ISO.

(2) The Authorized Commission employing or retaining the Authorized Person has provided the ISO with: (a) a final order of FERC prohibiting the release by the Authorized Person or the Authorized Commission of Confidential Market Information in accordance with the terms of this Information Policy and the Non-Disclosure Agreement; and (b) either an order of such Authorized Commission or a certification from counsel to such Authorized Commission, confirming that the Authorized Commission (i) has statutory authority to protect the confidentiality of any Confidential Market Information received from public release or disclosure and from release or disclosure to any other entity, (ii) will defend against any disclosure of Confidential Market Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders, (iii) will provide the ISO with prompt notice of any such Third Party Request or legal proceedings and will consult with the ISO and/or any Affected Governance Participant in its efforts to deny the Third Party

Request or defend against such legal process, (iv) in the event a protective order or other remedy is denied, will direct Authorized Persons authorized by it to furnish only that portion of the Confidential Market Information which their legal counsel advises the ISO in writing is legally required to be furnished, (v) will exercise its best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Market Information and (vi) has adequate procedures to protect against the release of such Confidential Market Information; and (c) confirmation in writing that the Authorized Person is authorized by the Commission to enter into the Non-Disclosure Agreement and to receive Confidential Market Information under this Information Policy.

(3) The Authorized Commission employing or retaining the Authorized Person has provided the ISO with a State Certification.

(4) The ISO and the External Market Monitor shall be expressly entitled to rely upon such FERC and Authorized Commission orders, the State Certification and/or certifications of counsel in providing Confidential Market Information to the Authorized Person, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder due to the ineffectiveness of the FERC and/or Commission orders, or the inaccuracy of such certification of counsel.

(5) The Authorized Person may discuss Confidential Market Information with other Authorized Persons who are parties to Non-Disclosure Agreements, provided; however, that the ISO shall have confirmed in advance and in writing that it has previously released the Confidential Market Information in question to such Authorized Persons. The ISO shall respond to any written request for confirmation within two (2) business days of its receipt.

(6) The ISO shall maintain a schedule of all Authorized Persons and the Authorized Commissions they represent, which shall be made publicly available on the ISO’s website or by written request. Such schedule shall be compiled by the ISO, based on information provided by any Authorized Person and/or Authorized Commission. The ISO shall update the schedule promptly upon receipt of information from an Authorized Person or Authorized Commission, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any

inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by the ISO in the compilation and/or maintenance of the schedule.

(ii) The External Market Monitor or other designated representative of the ISO may, in the course of discussions with any Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or their Authorized Commission to determine whether additional Information Requests for information are appropriate. The External Market Monitor or other representative of the ISO will not make any written or electronic disclosures of Confidential Market Information to the Authorized Person pursuant to this section. In any such discussions, the External Market Monitor or other representative of the ISO shall ensure that the individual or individuals receiving such Confidential Market Information are Authorized Persons as defined herein, request that the Authorized Person describe the purpose of the inquiry, orally designate Confidential Market Information that is disclosed, and refrain from identifying any specific Affected Governance Participant whose information is disclosed. The External Market Monitor or other representative of the ISO shall also be authorized to assist Authorized Persons in interpreting Confidential Market Information that is disclosed. The External Market Monitor or representative of the ISO shall provide any Affected Governance Participant and counsel for the Participants Committee with oral notice of any oral disclosure immediately, but not later than one (1) business day after the oral disclosure. Such oral notice to the Affected Governance Participant shall include the substance of the oral disclosure, but shall not reveal any Confidential Market Information of any other Governance Participant and must be received by the Affected Governance Participant before the name of the Affected Governance Participant is released to the Authorized Person, provided; however, the identity of the Affected Party must be made to the Authorized Person within two (2) business days of the initial oral disclosure. The ISO shall provide an Affected Governance Participant and counsel for the Participants Committee with written notice, which shall include electronic communication, of any oral disclosure as soon as possible, but not later than two (2) business days after the date of the oral disclosure.

(iii) As regards Information Requests:

(1) Information Requests to the ISO shall be in writing, which shall include electronic communications addressed to the External Market Monitor or other designated

representative of the ISO, and shall: (a) describe with particularity the information sought; (b) provide a description of the purpose of the Information Request; (c) state the time period for which Confidential Market Information is requested; and (d) re-affirm that only the Authorized Person shall have access to the Confidential Market Information requested. The ISO shall provide an Affected Governance Participant and counsel for the Participants Committee with written notice, which shall include electronic communication, of an Information Request of the Authorized Person as soon as possible, but not later than two (2) business days after the receipt of the Information Request.

(2) Subject to the provisions of section (iii)(3), the ISO shall supply Confidential Market Information to the Authorized Person in response to any Information Request within five (5) business days of the receipt of the Information Request, to the extent that the requested Confidential Market Information can be made available within such period, provided; however, that in no event shall Confidential Market Information be released prior to the end of the fourth (4th) business day without the express consent of the Affected Governance Participant. To the extent that the ISO cannot reasonably prepare and deliver the requested Confidential Market Information within such five (5) day period, it shall, within such period, provide the Authorized Person with a written schedule for the provision of such remaining Confidential Market Information. Upon providing Confidential Market Information to the Authorized Person, the ISO shall either provide a copy of the Confidential Market Information to the Affected Governance Participant(s), or provide a listing of the Confidential Market Information disclosed, provided; however, that the ISO shall not reveal any Governance Participant's Confidential Market Information to any other Governance Participant.

(3) Notwithstanding section (iii)(2), above, should the ISO, an Affected Governance Participant, or the Participants Committee (with respect to an Information Request that applies to multiple Governance Participants) object to an Information Request or any portion thereof, any of them may, within four (4) business days following the ISO's receipt of the Information Request, request, in writing, a conference with the Authorized Commission or the Authorized Commission's authorized designee to resolve differences concerning the scope or timing of the Information Request, provided; however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute.

Should such conference be refused by any participant, or not resolve the dispute, then the ISO, the Affected Governance Participant, the Participants Committee (with respect to an Information Request that applies to multiple Governance Participants) or the Authorized Commission may initiate appropriate legal action at FERC within three (3) business days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at FERC objecting to a particular Information Request shall be designated by the party as a “fast track” complaint and each party shall bear its own costs in connection with such FERC proceeding. If no FERC proceeding regarding the Information Request is commenced within such three day period, the ISO shall utilize its best efforts to respond to the Information Request promptly. During any pending FERC proceeding regarding an Information Request, the ISO shall continue to maintain the confidentiality of the Confidential Market Information subject to such Information Request.

(iv) In the event of any breach of a Non-Disclosure Agreement:

(1) The Authorized Person and/or their respective Authorized Commission shall promptly notify the ISO, who shall, in turn, promptly notify any Affected Governance Participant and counsel for the Participants Committee of any inadvertent or intentional release, or possible release, of Confidential Market Information provided pursuant to any Non-Disclosure Agreement.

(2) The ISO shall terminate such Non-Disclosure Agreement upon written notice to the Authorized Person and his or her Authorized Commission, and all rights of the Authorized Person thereunder shall thereupon terminate, provided; however, that the ISO may restore an individual’s status as an Authorized Person after consulting with the Affected Governance Participant and to the extent that: (i) the ISO determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Person; (ii) there were no harm or damage suffered by the Affected Governance Participant; or (iii) similar good cause shown. Any appeal of the ISO’s actions under this section shall be to FERC.

(3) The ISO, the Affected Governance Participant, and/or the Participants Committee shall have the right to seek and obtain at least the following types of relief: (a)

an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all Confidential Market Information to the ISO.

(4) No Authorized Person shall have responsibility or liability whatsoever under the Non-Disclosure Agreement or this Information Policy for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of Confidential Market Information to persons not authorized to receive it, provided that such Authorized Person is an employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this section (iv)(4) is intended to limit the liability of any person who is not an employee of or a member of an Authorized Commission at the, time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(5) Any dispute or conflict requesting the relief in section (iv)(2) or (iv)(3)(a) above, shall be submitted to FERC for hearing and resolution. Any dispute or conflict requesting the relief in section (4)(3)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

3.4 Disclosure to Academic Institutions

Notwithstanding anything to the contrary set forth herein, the ISO may disclose Confidential Market Information (as defined in Section 3.3), otherwise to be maintained in confidence pursuant to this Information Policy, to a research university (an “Authorized Institution”), solely for the purpose of academic research by Authorized Researchers (as defined below), under the following conditions:

(a) The Authorized Institution has delivered an information request to the ISO in writing (the “Academic Institution Information Request”), which shall include electronic communications addressed to the External Market Monitor, and shall: (i) describe with particularity the information sought; (ii) provide a description of the purpose of the Academic Institution Information Request (“Proposed Research”); (iii) state the time period for which the Confidential Market Information is requested; (iv) specify the individuals that will have access to such Confidential Market Information (the “Authorized Researchers”) and (v) specify the source of funding for the research to be performed with respect to the requested Confidential Market Information.

(b) The ISO shall review the merits of the Academic Institution Information Request and may, in its sole discretion, reject such request without providing notice to affected Governance Participants and the Participants Committee as required in subsection 3.4(c) below.

(c) In the event that the ISO does not initially reject the Academic Institution Information Request pursuant to subsection 3.4(b) above, the ISO shall provide affected Governance Participants and counsel to the Participants Committee with written notice, which shall include electronic communication, of an Academic Institution Information Request as soon as possible, but no later than five (5) business days after receipt of the Academic Institution Information Request. Such notice shall include all of the information contained in the Academic Institution Information Request.

(d) An authorized representative of the Authorized Institution has executed a non-disclosure agreement in the form attached hereto as Appendix C (the "Academic Institution Non-Disclosure Agreement") in which the Authorized Institution (i) represents and warrants that the Authorized Institution (w) will only share the Confidential Market Information with Authorized Researchers identified in the Academic Institution Information Request, solely to be used for the purpose of the Proposed Research; (x) is duly authorized to enter into and perform the obligations of the Academic Institution Non-Disclosure Agreement; (y) has adequate procedures to protect against the release of any Confidential Market Information received; and (z) is not in breach of any other Academic Institution Non-Disclosure Agreement entered into with the ISO; and (ii) covenants and agrees not to disclose the Confidential Market Information and to deny any third-party requests for the Confidential Market Information and defend against any legal process that seeks the release of any Confidential Market Information.

(e) The ISO shall provide affected Governance Participants and counsel to the Participants Committee written notice, which shall include electronic communication, of its determination whether to release Confidential Market Information in response to an Academic Institution Information Request as soon as possible, but no later than five (5) business days following the provision of the notice required in subsection (c) above. Notice of the ISO's determination shall also include all of the information contained in the Academic Institution Information Request, and shall inform the affected Governance Participants of their right to object to such release, as well as the deadline for any such objection and shall specifically state that in the event that the affected Governance Participants do not object to such release, any information released by the ISO pursuant to an Academic Institution Information Request may be subject to publication by the Authorized Institution; provided that such publication may only be made (x) upon written consent of the ISO and (y) if any material the Authorized Institution proposes to publish, which is related to or that relies upon the Confidential Market Information, is sufficiently redacted or summarized in a manner so that it may not be identified. The ISO shall not release Confidential Market Information relating to any affected Governance Participant that objects to such release within ten (10) business days of the ISO's notice of its determination. Following the tenth (10th) business day after providing such notice, the ISO may, in its sole discretion, release Confidential Market Information relating to those affected Governance Participants that have not objected to such release to the Authorized Institution, provided, however, that the ISO shall redact all Confidential Market Information relating to any objecting affected Governance Participants, as applicable.

(f) In the event that an Authorized Institution or any Authorized Researcher publishes any material related to or that relies upon the Confidential Market Information, upon written consent of the ISO in accordance with Section 2.3.4 of the Academic Institution Non-Disclosure Agreement, the ISO shall provide notice to the Participants Committee regarding the medium (e.g., journal) in which the publication has been made.

APPENDIX A

FORM OF NON-DISCLOSURE AGREEMENT

THIS NON-DISCLOSURE AGREEMENT (the “Agreement”) is made this ______ day of _______________, 2004, by and between _______________________, an Authorized Person, as defined below, of __________________ (the “State Commission”) having jurisdiction within the State of ____________________, with offices at _________________________________ and ISO New England Inc., a Delaware corporation, with offices at One Sullivan Road, Holyoke, Massachusetts, 01040-2841 (“ISO”). The State Commission and ISO shall be referred to herein individually as a “Party,” or collectively as the “Parties.”

RECITALS

Whereas, ISO serves as the Regional Transmission Organization for the New England Control Area, and operates and oversees wholesale markets for electricity pursuant to the requirements of the ISO Tariff, as defined below; and

Whereas, the External Market Monitor (as defined below) serves as the independent market monitor for ISO’s wholesale markets for electricity, and

Whereas, the ISO New England Information Policy requires that ISO and the External Market Monitor maintain the confidentiality of Confidential Market Information; and

Whereas, the ISO New England Information Policy requires ISO and the External Market Monitor to disclose Confidential Market Information to Authorized Persons upon satisfaction of conditions stated in the ISO New England Information Policy, including, but not limited to, the execution of this Agreement by the Authorized Person and the maintenance of the confidentiality of such information pursuant to the terms of this Agreement; and

Whereas, ISO desires to provide Authorized Persons with the broadest possible access to Confidential Market Information, consistent with ISO’s and the External Market Monitor’s obligations and duties under the ISO New England Information Policy, the ISO Tariff and other applicable FERC directives; and

Whereas, this Agreement is a statement of the conditions and requirements, consistent with the requirements of the ISO New England Information Policy, whereby ISO and the External Market Monitor may provide Confidential Market Information to the Authorized Person.

NOW, THEREFORE, intending to be legally bound, the Parties hereby agree as follows:

1. Definitions

1.1 Affected Governance Participant. A Governance Participant, which as a result of its participation in the markets administered by ISO, provided Confidential Market Information to ISO, which Confidential Market Information is requested by, or is disclosed to an Authorized Person under this Agreement.

1.2 Authorized Commission. A State public utility commission within the geographic limits of the New England Control Area (as that term in defined in the ISO Tariff) that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State.

1.3 Authorized Person. A person , including the undersigned, which has executed this Agreement and that is authorized in writing by an Authorized Commission to receive and discuss Confidential Market Information. Authorized Persons may include attorneys representing an Authorized Commission, consultants and/or contractors directly employed or retained by an Authorized Commission, provided however that consultants or contractors may not initiate requests for Confidential Market Information from ISO or the External Market Monitor.

1.4 Confidential Market Information. Shall mean *Confidential Information* (as defined in the ISO New England Information Policy) consisting of market data relating to the markets administered by ISO, including data supplied by Governance Participants and aggregate data regularly compiled by ISO. Confidential Market Information shall not include the following categories of information without excluding any objective market data associated with them that would otherwise be provided under the first sentence of this definition: (i) draft versions of reports and analyses, (ii) internal ISO documents not related to market data, (iii) attorney-client communications, (iv) attorney work-product privileged information, (v) communications about Confidential Market Information between an Affected Governance Participant and the ISO/External Market Monitor, except to the extent that the communications become part of final written reports or final written analyses by the ISO/External Market

Monitor, (vi) communications between an Affected Governance Participant and ISO made on a confidential basis as part of a settlement proceeding or negotiation; and (vii) information provided to ISO on a confidential basis as part of an Alternative Dispute Resolution proceeding.

1.5 External Market Monitor. Shall have the meaning set forth in the ISO Tariff.

1.6 FERC. The Federal Energy Regulatory Commission.

1.7 Governance Participant. Shall have the meaning set forth in the ISO Tariff.

1.8 ISO New England Information Policy. Shall have the meaning set forth in the ISO Tariff.

1.9 Information Request. A written request, in accordance with the terms of this Agreement for disclosure of Confidential Market Information pursuant to Section 3.3 of the ISO New England Information Policy.

1.10 ISO Tariff. ISO's Transmission, Markets and Services Tariff, as it may be amended from time to time.

1.11 Third Party Request. Any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of Confidential Market Information. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for Confidential Market Information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

2. Protection of Confidentiality.

2.1 Duty to Not Disclose. The Authorized Person represents and warrants that he or she: (i) is presently an Authorized Person as defined herein; (ii) is duly authorized to enter into and perform this Agreement; (iii) has adequate procedures to protect against the release of Confidential Market Information, and (iv) is familiar with, and will comply with, all such applicable State Commission procedures. The Authorized Person hereby covenants and agrees on behalf of himself or herself not to disclose the Confidential Market Information and to deny any Third Party Request and defend against any legal process which seeks the release of Confidential Market Information in contravention of the terms of this Agreement.

2.2 Conditions Precedent. As a condition of the execution, delivery and effectiveness of this Agreement by ISO and the continued provision of Confidential Market Information pursuant to the terms of this Agreement, the Authorized Commission shall, prior to the initial oral or written request for Confidential Market Information by an Authorized Person on its behalf, provide ISO with: (a) a final order of FERC prohibiting the release by the Authorized Person or the State Commission of Confidential Market Information in accordance with the terms of the Operating Agreement and this Agreement; and (b) either an order of the State Commission or a certification from counsel to the State Commission, confirming that the State Commission has statutory authority to protect the confidentiality of the Confidential Market Information from public release or disclosure and from release or disclosure to any other entity, and that it has adequate procedures to protect against the release of Confidential Market Information; and (c) confirmation in writing that the Authorized Person is authorized by the State Commission to enter into this Agreement and to receive Confidential Market Information under the ISO New England Information Policy.

2.3 Discussion of Confidential Market Information with other Authorized Persons. The Authorized Person may discuss Confidential Market Information with other Authorized Persons who have executed non-disclosure agreements with ISO containing the same terms and conditions as this Agreement; provided, however, that ISO shall have confirmed in advance and in writing that ISO has previously released the Confidential Market Information in question to such Authorized Persons. ISO shall respond to any written request for confirmation within two (2) business days of its receipt.

2.4 Defense Against Third Party Requests. The Authorized Person shall defend against any disclosure of Confidential Market Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders. The Authorized Person shall provide ISO, and ISO shall provide each Affected Governance Participant and counsel for the Participants Committee, with prompt notice of any such Third Party Request or legal proceedings, and shall consult with ISO and/or any Affected Governance Participant in its efforts to deny the request or defend against such legal process. In the event a protective order or other remedy is denied, the Authorized Person agrees to furnish only that portion of the Confidential Market Information which their legal counsel advises ISO (and of which ISO shall, in turn, advise any Affected Governance Participants) in writing is legally required to be furnished, and to exercise their best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Market Information.

2.5 Care and Use of Confidential Market Information.

2.5.1 Control of Confidential Market Information. The Authorized Person(s) shall be the custodian(s) of any and all Confidential Market Information received pursuant to the terms of this Agreement from ISO or the External Market Monitor.

2.5.2 Access to Confidential Market Information. The Authorized Person shall ensure that Confidential Market Information received by that Authorized Person is disseminated only to those persons publicly identified as Authorized Persons on Exhibit "A" to the certification provided by the State Commission pursuant to the procedures contained in Section 2.2 of this Agreement.

2.5.3 Schedule of Authorized Persons.

(i) The Authorized Person shall promptly notify ISO of any change that would affect the Authorized Person's status as an Authorized Person, and in such event shall request, in writing, deletion from the schedule referred to in section (ii), below.

(ii) ISO shall maintain a schedule of all Authorized Persons and the Authorized Commissions they represent, which shall be made publicly available on ISO's website and/or by written request. Such schedule shall be compiled by ISO, based on information provided by any Authorized Person and/or Authorized Commission. ISO shall update the schedule promptly upon receipt of information from an Authorized Person or Authorized Commission, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by ISO in the compilation and/or maintenance of the schedule.

2.5.4 Use of Confidential Market Information. The Authorized Person and his or her Authorized Commission shall use the Confidential Market Information solely for the purpose of assisting the Authorized Commission in discharging its legal responsibility to monitor the wholesale and retail electricity markets, operations, transmission planning and siting, and generation planning and siting materially affecting retail customers within the State in which the Authorized Commission has regulatory jurisdiction, and for no other purpose. Without limiting the foregoing, the Authorized Person and his or her Authorized Commission shall not use its right to acquire Confidential Market Information as a means of conducting discovery or providing evidence during an adversarial proceeding against an Affected Governance Participant or any group of Participants. The Authorized Person and his or her Authorized Commission, however, shall not be prevented from using in an adversarial proceeding Confidential Market Information the Authorized Commission has obtained if: (i) such information becomes known in that proceeding through disclosure by entities other than the Authorized Commission; and (ii) the Authorized Commission discloses such Confidential Market Information consistent with the protections and procedures governing the disclosure of Confidential Market Information to parties in that proceeding; or (iii) the information being disclosed no longer meets the definition of Confidential Market Information.

2.5.5 Return of Confidential Market Information. Upon completion of the inquiry or investigation referred to in the Information Request, or for any reason the Authorized Person is, or will no longer be an Authorized Person, the Authorized Person shall (a) return the Confidential Market Information and all copies thereof to ISO, or (b) provide a certification that the Authorized Person has destroyed all paper copies and deleted all electronic copies of the Confidential Market Information, unless such actions are inconsistent with or prohibited by applicable state law, in which case the Authorized Person shall continue to maintain the confidentiality of the Confidential Market Information in accordance with the terms and conditions of this Agreement. ISO may waive this condition in writing if such Confidential Market Information has become publicly available or non-confidential in the course of business or pursuant to the ISO Tariff or order of the FERC.

2.5.6 Notice of Disclosures. The Authorized Person, directly or through the Authorized Commission, shall promptly notify ISO, and ISO shall promptly notify any Affected Governance Participant, of any inadvertent or intentional release or possible release of the Confidential Market Information provided pursuant to this Agreement. The Authorized Person shall take all steps to minimize any further release of Confidential Market Information, and shall take reasonable steps to attempt to retrieve any Confidential Market Information that may have been released.

2.6 Ownership and Privilege. Nothing in this Agreement, or incident to the provision of Confidential Market Information to the Authorized Person pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against, subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Market Information is intended or shall be inferred by the disclosure of Confidential Market Information by ISO, and any and all intellectual property comprising Confidential Market Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of ISO and/or the Affected Governance Participant.

3. Procedure for Information Requests

3.1 Written Requests. Information Requests to ISO shall be in writing, which shall include electronic communications, addressed to the External Market Monitor or other ISO representatives as specified by ISO, with a concurrent copy to ISO's General Counsel, and shall: (a) describe with particularity the information sought; (b) provide a description of the purpose of the Information Request; (c) state the time period for which information is requested; and (d) re-affirm that only the Authorized Person shall have access to the Confidential Market Information requested. ISO shall provide an Affected Governance Participant and counsel for the Participants Committee with written notice, which shall include electronic communication, of an Information Request of the Authorized Person as soon as possible, but not later than two (2) business days after the receipt of the Information Request.

3.2 Oral Disclosures by the External Market Monitor. The External Market Monitor or other ISO representatives as specified by ISO may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the State Commission to determine whether additional Information Requests for information are appropriate. The External Market Monitor or other ISO representative will not make any written or electronic disclosures of Confidential Market Information to the Authorized Person pursuant to this section. In any such discussions, the External Market Monitor or other ISO representative shall ensure that the individual or individuals receiving such Confidential Market Information are Authorized Persons under this Agreement, request that the Authorized Person describe the purpose of the inquiry, orally designate Confidential Market Information that is disclosed and refrain from identifying any specific Affected Governance Participant whose information is disclosed. The External Market Monitor or other ISO representative shall also be authorized to assist Authorized Persons in interpreting Confidential Market Information that is disclosed. ISO or the External Market Monitor shall (i) maintain a written record of oral disclosures pursuant to this section, which shall include the date of each oral disclosure and the Confidential Market Information disclosed in each such oral disclosure, and (ii) provide any Affected Governance Participant and counsel for the Participants Committee with oral notice of any oral disclosure immediately, but not later than one (1) business day after the oral disclosure. Such oral notice to the

Affected Governance Participant shall include the substance of the oral disclosure, but shall not reveal any Confidential Market Information of any other Governance Participant and must be received by the Affected Governance Participant before the name of the Affected Governance Participant is released to the Authorized Person; provided however, the identity of the Affected Party must be made available to the Authorized Person within two (2) business days of the initial oral disclosure. ISO shall provide an Affected Governance Participant and counsel for the Participants Committee with written notice, which shall include electronic communication, of any oral disclosure as soon as possible, but not later than two (2) business days after the date of the initial oral disclosure.

3.3 Response to Information Requests.

3.3.1 Subject to the provisions of Section 3.3.2 below, ISO shall supply Confidential Market Information to the Authorized Person in response to any Information Request within five (5) business days of the receipt of the Information Request, to the extent that the requested Confidential Market Information can be made available within such period; provided however, that in no event shall Confidential Market Information be released prior to the end of the fourth (4th) business day without the express consent of the Affected Governance Participant. To the extent that ISO can not reasonably prepare and deliver the requested Confidential Market Information within such five (5) day period, ISO shall, within such period, provide the Authorized Person with a written schedule for the provision of such remaining Confidential Market Information. Upon providing Confidential Market Information to the Authorized Person, ISO shall either provide a copy of the Confidential Market Information to the Affected Governance Participant(s), or provide a listing of the Confidential Market Information disclosed; provided, however, that ISO shall not reveal any Governance Participant’s Confidential Market Information to any other Governance Participant.

3.3.2 Notwithstanding section 3.3.1, above, should ISO or an Affected Governance Participant or the Participants Committee (with respect to an Information Request that applies to multiple Governance Participants) object to an Information Request or any portion thereof, ISO, the Affected Governance Participant and/or the Participants Committee may, within four (4) business days following ISO’s receipt of the Information Request, request, in writing (which shall include electronic communication) addressed to the State Commission with a copy to either the Affected Governance Participant, ISO and/or counsel to the Participants Committee, as the case may be, a conference with the State Commission or the State Commission’s authorized designee to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the State Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute. Should such conference be refused by any participant, or not resolve the dispute, then ISO, the Affected Governance Participant, the Participants Committee (with respect to an Information Request that applies to multiple Governance Participants) or the State Commission may initiate appropriate legal action at FERC within three (3) business days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. If no FERC proceeding regarding the Information Request is commenced by ISO, the Affected Governance Participant or the State Commission within such three day period, ISO shall utilize its best efforts to respond to the Information Request promptly. During any pending FERC proceeding regarding an Information Request, ISO shall continue to maintain the confidentiality of the Confidential Market Information subject to such Information Request.

3.3.3 To the extent that a response to any Information Request requires disclosure of Confidential Market Information of two or more Affected Governance Participants, ISO shall, to the extent possible, segregate such information and respond to the Information Request separately for each Affected Governance Participant.

4. Remedies.

4.1 Material Breach. The Authorized Person agrees that release of Confidential Market Information to persons not authorized to receive it constitutes a breach of this Agreement and may cause irreparable harm to ISO and/or the Affected Governance Participant. In the event of a breach of this Agreement by the Authorized Person, ISO shall terminate this Agreement upon written notice to the Authorized Person and his or her Authorized Commission, and all rights of the Authorized Person hereunder shall thereupon terminate; provided, however, that ISO may restore an individual's status as an Authorized Person after consulting with the Affected Governance Participant and to the extent that: (i) ISO determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Person; (ii) there were no harm or damages suffered by the Affected Governance Participant; or (iii) similar good cause shown. Any appeal of ISO's actions under this section shall be to FERC.

4.2 Judicial Recourse. In the event of any breach of this Agreement, ISO, the Affected Governance Participant and/or the Participants Committee shall have the right to seek and obtain at least the following types of relief: (a) an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all Confidential Market Information to ISO. The Authorized Person expressly agrees that in the event of a breach of this Agreement, any relief sought properly includes, but shall not be limited to, the immediate return of all Confidential Market Information to ISO.

4.3 Waiver of Monetary Damages. No Authorized Person shall have responsibility or liability whatsoever under this Agreement for any and all liabilities, losses,
damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of, or in connection with, the release of Confidential Market Information to persons not authorized to receive it, provided that such Authorized Person is an employee or Governance Participant of an Authorized Commission at the time of such unauthorized release. Nothing in this Section 4.3 is intended to limit the liability of any person who is not an employee of or a Governance Participant of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

5. Jurisdiction. The Parties agree that (i) any dispute or conflict requesting the relief in sections 4.1 and 4.2(a) above shall be submitted to FERC for hearing and resolution; (ii) any dispute or conflict requesting the relief in section 4.2(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution; and (iii) jurisdiction over all other actions and requested relief shall lie in any court of competent jurisdiction.

6. Notices. All notices required pursuant to the terms of this Agreement shall be in writing, and served at the following addresses or email addresses:

If to the Authorized Person:

-

____

__

____

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(email address)

with a copy to

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(email address)

If to Counsel for the Participants Committee:

____

____

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(email address)

with a copy to

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(email address)

If to ISO:

____

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(email address)

with a copy to

____

____

____

(email address)

7. **Severability and Survival.** In the event any provision of this Agreement is determined to be unenforceable as a matter of law, the Parties intend that all other provisions of this Agreement remain in full force and effect in accordance with their terms. In the event of conflicts between the terms of this Agreement and the Operating Agreement, the terms of the Operating Agreement shall in all events be controlling. The Authorized Person acknowledges that any and all obligations of the Authorized Person hereunder shall survive the severance or termination of any employment or retention relationship between the Authorized Person and their respective Authorized Commission.

8. **Representations.** The undersigned represent and warrant that they are vested with all necessary corporate, statutory and/or regulatory authority to execute and deliver this Agreement, and to perform all of the obligations and duties contained herein.

9. **Third Party Beneficiaries**. The Parties specifically agree and acknowledge that each Governance Participant is an intended third party beneficiary of this Agreement entitled to enforce its provisions.

10. **Counterparts.** This Agreement may be executed in counterparts and all such counterparts together shall be deemed to constitute a single executed original.

11. **Amendment**. This Agreement may not be amended except by written agreement executed by authorized representatives of the Parties.

ISO NEW ENGLAND INC.	AUTHORIZED PERSON
By:	By:
________________________________	________________________________
Name:	Name:
Title:	Title:

APPENDIX B
FORM OF CERTIFICATION

This Certification (the "Certification") is given this _____ day of ________________, 200_, by ______________________________, a __________________________ (the "Authorized Commission"), to and for the benefit of ISO New England Inc. ("ISO") and its Governance Participants. The Authorized Commission and ISO shall be referred to herein collectively as the "Parties".

Whereas, the Authorized Commission has designated the individuals on attached Exhibit "A" (the "Authorized Persons") to receive Confidential Market Information from ISO, and

Whereas, the Authorized Persons and ISO have, or will, enter into non-disclosure agreements, governing the rights and obligations of the Authorized Persons, ISO and others regarding the Authorized Persons' access to, provision of, use and control of the Confidential Market Information (the "Non-Disclosure Agreements"), and

Whereas, as a condition precedent to the execution of the Non-Disclosure Agreements and provision of Confidential Market Information to the Authorized Persons, the Authorized Commission is required to make certain representations and warranties to ISO, and

Whereas, ISO agrees to provide Confidential Market Information to the Authorized Persons, in their capacity as agents of the Authorized Commission, subject to the terms of this Certification, the Non-Disclosure Agreements, and an appropriate order of the Federal Energy Regulatory Commission protecting the confidentiality of such data;

Whereas, the Parties desire to set forth those representations and warranties herein.

Now, therefore, the Authorized Commission hereby makes the following representations and warranties, all of which shall be true and correct as of the date of execution of this Certification, and at all times thereafter, and with the express understanding that ISO and any Affected Member shall rely on each representation and/or warranty:

1. Definitions. Terms contained, but not defined, herein shall have the definitions or meanings ascribed to such terms in the Non-Disclosure Agreement or the ISO New England Information Policy.

2. Requisite Authority.

a. The Authorized Commission hereby certifies that it has all necessary legal authority to execute, deliver, and perform the obligations in this Certification.

b. Each Authorized Person is, at the time of the execution of this Certification, an employee of, or consultant to, the Authorized Commission, and has not materially breached any existing or past nondisclosure agreement or obligation, except as has been disclosed by the Authorized Commission to ISO in writing.

c. The Authorized Persons have, through all necessary action of the Authorized Commission, been appointed and directed by the Authorized Commission to execute and deliver the Non-Disclosure Agreements to ISO and receive Confidential Market Information on the Authorized Commission's behalf and for its benefit.

d. The Authorized Commission will, at all times after the provision of Confidential Market Information to the Authorized Persons, provide ISO with: (i) written notice of any changes in the Authorized Persons' qualification as an Authorized Person within two (2) business days of such change; (ii) written confirmation to any inquiry by ISO regarding the status or identification of any specific Authorized Person within two (2) business days of such request, and (iii) periodic written updates, no less often than semi-annually, containing the names of all Authorized Persons appointed by the Authorized Commission.

3. Protection of Confidential Market Information.

a. The Authorized Commission has adequate internal procedures, to protect against the release of any Confidential Market Information by the Authorized Persons or other employee or agent of the Authorized Commission, and the Authorized Commission and the Authorized Persons will strictly enforce and periodically review all such procedures. In the event that ISO terminates a Non-Disclosure Agreement with an Authorized Person, and does not restore such individual's status as an Authorized Person, then the Authorized Commission shall review such internal procedures.

b. The Authorized Commission has legal authority to protect the confidentiality of Confidential Market Information from public release or disclosure and/or from release or disclosure to any other person or entity, either by the Authorized Commission or the Authorized Persons, as agents of the Authorized Commission.

c. The Authorized Commission shall ensure that Confidential Market Information and shall be maintained by, and accessible only to, the Authorized Persons.

d. The Authorized Commission and its Authorized Person(s) shall not disclose the Confidential Market Information.

4. Defense Against Requests for Disclosure. The Authorized Commission shall defend against, and will direct the Authorized Persons to defend against, disclosure of any Confidential Market Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders. The Authorized Commission shall provide ISO with prompt notice of any such Third Party Request or legal proceedings, and shall consult with ISO and/or any Affected Governance Participant in its efforts to deny the request or defend against such legal process. In the event a protective order or other remedy is denied, the Authorized Commission agrees to furnish only that portion of the Confidential Market Information which their legal counsel advises ISO (and of which ISO shall, in turn, advise any Affected Member) in writing is legally required to be furnished, and to exercise then-best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Market Information.

5. Use and Destruction of Confidential Market Information.

a. The Authorized Commission shall use, and allow the use of, the Confidential Market Information solely for the purpose of assisting the Authorized Commission in discharging its legal responsibility to monitor the wholesale and retail electricity markets, operations, transmission planning and siting, and generation planning and siting materially affecting retail customers within the State in which the Authorized Commission has regulatory jurisdiction, and for no other purpose. Without limiting the foregoing, the Authorized Commission shall not use its right to acquire Confidential Market Information as a means of conducting discovery or providing evidence during an adversarial proceeding against an Affected Governance Participant or any group of Participants. The Authorized Commission, however, shall not be prevented from using in an adversarial proceeding Confidential Market Information the Authorized Commission has obtained if: (i) such information becomes known in that proceeding through disclosure by entities other than the Authorized Commission; and (ii) the Authorized Commission discloses such

Confidential Market Information consistent with the protections and procedures governing the disclosure of Confidential Market Information to parties in that proceeding; or (iii) the information being disclosed no longer meets the definition of Confidential Market Information.

b. Upon completion of the inquiry or investigation referred to in any Information Request initiated by or on behalf of the Authorized Commission, or for any reason any Authorized Person is, or will no longer be an Authorized Person, the Authorized Commission will ensure that such Authorized Person either (a) returns the Confidential Market Information and all copies thereof to ISO, or (b) provides a certification that the Authorized Person and/or the Authorized Commission has destroyed all paper copies and deleted all electronic copies of the Confidential Market Information, unless such actions are inconsistent with or prohibited by applicable state law, in which case the Authorized Commission shall continue to maintain the confidentiality of the Confidential Market Information in accordance with the terms and conditions of this Certification.

6. Notice of Disclosure of Confidential Market Information. The Authorized Commission shall promptly notify ISO of any inadvertent or intentional release or possible release of the Confidential Market Information provided to any Authorized Person, and shall take all available steps to minimize any further release of Confidential Market Information and/or retrieve any Confidential Market Information that may have been released.

7. Ownership and Privilege. Nothing in this Certification, or incident to the provision of Confidential Market Information to the Authorized Person pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Market Information is intended or shall be inferred by the disclosure of Confidential Market Information by ISO, and any and all intellectual property comprising Confidential Market Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of ISO and/or the Affected Governance Participant.

Executed, as of the date first set out above.

[Commission]

By:______________________________

Its:______________________________

[SEE NEXT PAGE]

EXHIBIT A

CERTIFICATION LIST OF AUTHORIZED PERSONS

Name of Authority	Mailing Address	Email	Tel #	Scope and Duration

APPENDIX C

FORM OF ACADEMIC INSTITUTION NON-DISCLOSURE AGREEMENT

THIS NON-DISCLOSURE AGREEMENT (the “Agreement”) is made this ______ day of ________________, 200_, by and between ________________________, (the “Authorized Institution”), with offices at __________________________________ and ISO New England Inc., a Delaware corporation, with offices at One Sullivan Road, Holyoke, Massachusetts, 01040-2841 (the “ISO”). The Authorized Institution and the ISO shall be referred to herein individually as a “Party,” or collectively as the “Parties.”

RECITALS

Whereas, the ISO serves as the Regional Transmission Organization for the New England Control Area, and operates and oversees wholesale markets for electricity pursuant to the requirements of the ISO Tariff, as defined below; and

Whereas, the External Market Monitor (as defined below) serves as the independent market monitor for ISO’s wholesale markets for electricity, and

Whereas, the ISO New England Information Policy requires that the ISO and the External Market Monitor maintain the confidentiality of Confidential Market Information; and

Whereas, the ISO New England Information Policy permits the ISO and the External Market Monitor to disclose Confidential Market Information to the Authorized Institution upon satisfaction of conditions stated in the ISO New England Information Policy, including, but not limited to, the execution of this Agreement by the Authorized Institution and the maintenance of the confidentiality of such information by the Authorized Institution pursuant to the terms of this Agreement; and

Whereas, the ISO desires to provide the Authorized Institution with access to Confidential Market Information, consistent with the ISO’s and the External Market Monitor’s obligations and duties under the ISO New England Information Policy, the ISO Tariff and other applicable FERC directives; and

Whereas, this Agreement is a statement of the conditions and requirements, consistent with the requirements of the ISO New England Information Policy, whereby the ISO may provide Confidential Market Information to the Authorized Institution.

NOW, THEREFORE, intending to be legally bound, the Parties hereby agree as follows:

1. **Definitions.** Capitalized terms not otherwise defined herein shall have the meanings ascribed thereto in the ISO Tariff.

1.1 **Affected Governance Participant**. A Governance Participant, which as a result of its participation in the markets administered by the ISO, provided Confidential Market Information to the ISO, which Confidential Market Information is requested by, or is disclosed to an Authorized Institution under this Agreement.

1.2 **Authorized Researcher**. Shall have the meaning set forth in the ISO New England Information Policy.

1.3 **Confidential Market Information**. Shall mean *Confidential Information* (as defined in the ISO New England Information Policy) consisting of market data relating to the markets administered by the ISO, including data supplied by Governance Participants and aggregate data regularly compiled by the ISO. Confidential Market Information shall not include the following categories of information without excluding any objective market data associated with them that would otherwise be provided under the first sentence of this definition: (i) draft versions of reports and analyses, (ii) internal ISO documents not related to market data, (iii) attorney-client communications, (iv) attorney work-product privileged information, (v) communications about Confidential Market Information between an Affected Governance Participant and the ISO/External Market Monitor, except to the extent that the communications become part of final written reports or final written analyses by the ISO/External Market Monitor, (vi) communications between an Affected Governance Participant and the ISO made on a confidential basis as part of a settlement proceeding or negotiation, and (vii) information provided to the ISO on a confidential basis as part of an Alternative Dispute Resolution proceeding. If the aforementioned information in (i) through (vii) is furnished to the Authorized Institution, such information shall be protected according to the terms of this Agreement, and the Authorized Institution shall return such information to the ISO as promptly as possible.

1.4 Competitive Duty Personnel. Shall mean a person whose duties include (i) the marketing or sale of electric power at wholesale; (ii) the purchase or resale of electric power at wholesale; (iii) the direct supervision of any employee with duties specified in subparagraph (i) or (ii) of this paragraph; or (iv) the provision of electricity marketing consulting services to entities engaged in the sale or purchase of electric power at wholesale.

1.5 FERC. The Federal Energy Regulatory Commission.

1.6 External Market Monitor. Shall have the meaning set forth in the ISO Tariff.

1.7 Governance Participant. Shall have the meaning set forth in the ISO Tariff.

1.8 ISO New England Information Policy. Shall have the meaning set forth in the ISO Tariff.

1.9 Information Request. A written request by the Authorized Institution in accordance with the terms of this Agreement for disclosure of Confidential Market Information pursuant to Section 3.4 of the ISO New England Information Policy.

1.10 ISO Tariff. The ISO's Transmission, Markets and Services Tariff, as it may be amended from time to time.

1.11 Non-Disclosure Certificate. Shall mean the certificate annexed hereto by which Authorized Researchers who have been granted access to Confidential Market Information shall certify their understanding that such access to Confidential Market Information is provided pursuant to the terms and restrictions of this Agreement, that they are not Competitive Duty Personnel, and that they have read this Agreement and agree to be bound by it.

1.12 Notes of Confidential Market Information. Shall mean memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in the definition of Confidential Market Information set forth above. Notes of Confidential Market Information are subject to the same restrictions provided in this Agreement for Confidential Market Information except as specifically provided in this Agreement.

1.13 Proposed Research. Shall have the meaning set forth in Section 3.4 of the Information Policy.

1.14 Third Party Request. Any request or demand by any entity upon the Authorized Institution for release or disclosure of Confidential Market Information. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for Confidential Market Information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

2. Protection of Confidentiality.

2.1 Duty to Not Disclose. The Authorized Institution represents and warrants that it:
(i) is duly authorized to enter into and perform this Agreement; (ii) has adequate procedures to protect against the release of Confidential Market Information; and (iii) is familiar with, and will comply with, all such applicable procedures. The Authorized Institution hereby covenants and agrees not to disclose the Confidential Market Information and to deny any Third Party Request and defend against any legal process that seeks the release of Confidential Market Information in contravention of the terms of this Agreement.

2.2 Defense Against Third Party Requests. The Authorized Institution shall defend against any disclosure of Confidential Market Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders. The Authorized Institution shall provide the ISO, and the ISO shall provide each Affected Governance Participant and counsel for the Participants Committee, with prompt notice of any such Third Party Request or legal proceedings, and shall consult with the ISO and/or any Affected Governance Participant in its efforts to deny the request or defend against such legal process. In the event a protective order or other remedy is denied, the Authorized Institution agrees to furnish only that portion of the Confidential Market Information which its legal counsel advises the ISO (and of which the ISO shall, in turn, advise any Affected Governance Participants) in writing is legally required to be furnished, and to exercise its best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Market Information.

2.3 Care and Use of Confidential Market Information.

2.3.1 Control of Confidential Market Information. The Authorized Institution shall be the custodian of any and all Confidential Market Information received pursuant to the terms of this Agreement from the ISO or the External Market Monitor.

2.3.2 Access to Confidential Market Information. The Authorized Institution shall ensure that Confidential Market Information received by that Authorized Institution is disseminated only to those persons publicly identified as Authorized Researchers in the applicable Information Request, and that such Authorized Researchers have been advised of the confidential nature of the Confidential Market Information and have agreed to abide by the terms of this Agreement by signing a Non-Disclosure Certificate. The Authorized Institution agrees that it shall be liable for any breach of this Agreement by any of the Authorized Researchers.

2.3.3 Competitive Duty Personnel. If any person who has been an "Authorized Researcher" subsequently becomes Competitive Duty Personnel, that person shall thereafter have no access to Confidential Market Information, shall return all such materials to the Authorized Institution, and shall continue to comply with the requirements set forth in this Non-Disclosure Agreement with respect to Confidential Market Information to which such person previously had access.

2.3.4 Use of Confidential Market Information. The Authorized Institution shall use the Confidential Market Information solely for the purpose of the Proposed Research. An Authorized Researcher may make copies of Confidential Market Information, but such copies become Confidential Market Information. An Authorized Researcher may make notes of Confidential Market Information, which shall be treated as Notes of Confidential Market Information if they disclose the contents of Confidential Market Information. In the event that the Authorized Institution or any Authorized Researcher desires to publish any material related to or that relies upon the Confidential Market Information, the Authorized Institution or Authorized Researcher must ensure that the Confidential Market Information is sufficiently redacted or summarized so that it may not be identified. Any such publication must be approved in writing by the ISO in advance of its release.

2.3.5 Return of Confidential Market Information. Upon completion of the Proposed Research, or upon termination of this Agreement for any reason, the Authorized Institution shall (a) return the Confidential Market Information and all copies thereof to the ISO, or (b) provide a certification that the Authorized Institution has destroyed all paper copies and deleted all electronic copies of the Confidential Market Information. The ISO may waive this condition in writing if such Confidential Market

Information has become publicly available or non-confidential in the course of business or pursuant to the ISO Tariff or order of the FERC.

2.3.6 Notice of Disclosures. The Authorized Institution shall promptly notify the ISO, and the ISO shall promptly notify any Affected Governance Participant, of any inadvertent or intentional release or possible release of the Confidential Market Information provided pursuant to this Agreement.
The Authorized Institution shall take all steps to minimize any further release of Confidential Market Information, and shall take reasonable steps to attempt to retrieve any Confidential Market Information that may have been released.

2.4 Ownership and Privilege. Nothing in this Agreement, or incident to the provision of Confidential Market Information to the Authorized Institution pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against, subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Market Information is intended or shall be inferred by the disclosure of Confidential Market Information by the ISO, and any and all intellectual property comprising Confidential Market Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of the ISO and/or the Affected Governance Participant.

3. Remedies.

3.1 Material Breach. The Authorized Institution agrees that any release of Confidential Market Information to persons not authorized to receive it or any publication of any material related to or that relies upon the Confidential Market Information which is not (i) approved in writing by the ISO prior to publication and (ii) redacted or summarized in such a manner that the Confidential Market Information may not be identified shall constitute a breach of this Agreement and may cause irreparable harm to the ISO and/or the Affected Governance Participant. In the event of a breach of this Agreement by the Authorized Institution, the ISO may terminate this Agreement upon written notice to the Authorized Institution, and all rights of the Authorized Institution hereunder shall thereupon terminate; provided, however, that the ISO may restore status as an Authorized Institution after consulting with the Affected Governance Participant and to the extent that: (i) the ISO determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Institution; (ii) there were no harm or damages suffered by the Affected Governance Participant; or (iii) similar good cause shown.

Notwithstanding the foregoing, the Authorized Institution hereby shall indemnify, save, hold harmless, discharge, and release the ISO and each affected Governance Participant from and against any and all payments, liabilities, damages, losses or costs and expenses paid or directly incurred by the ISO and/or each affected Governance Participant arising from, based upon, related to, or associated with the breach of, or failure to perform or satisfy, any obligation of the Authorized Institution set forth in this Agreement.

3.2 Judicial Recourse. In the event of any breach of this Agreement, the ISO, the Affected Governance Participant and/or the Participants Committee shall have the right to seek and obtain at least the following types of relief: (a) temporary, preliminary, and/or permanent injunctive relief with respect to any breach and (b) the immediate return of all Confidential Market Information to the ISO. The Authorized Institution expressly agrees that in the event of a breach of this Agreement, any relief sought properly includes, but shall not be limited to, the immediate return of all Confidential Market Information to the ISO.

4. Jurisdiction. The Parties agree that jurisdiction over all other actions and requested relief with respect to the Agreement shall lie in any court of competent jurisdiction.

5. Notices. All notices required pursuant to the terms of this Agreement shall be in writing, and served at the following addresses or email addresses:

If to the Authorized Institution:

-

____

____

____

(email address)

____

____

___

with a copy to

__

__

__

(email address)

If to Counsel for the Participants Committee:

_

_

_

(email address)

with a copy to

_

_

(email address)

If to ISO:

(email address)

with a copy to

(email address)

6. Severability and Survival. In the event any provision of this Agreement is determined to be unenforceable as a matter of law, the Parties intend that all other provisions of this Agreement remain in full force and effect in accordance with their terms.

7. Representations. The undersigned represent and warrant that they are vested with all necessary corporate, statutory and/or regulatory authority to execute and deliver this Agreement, and to perform all of the obligations and duties contained herein.

8. Third Party Beneficiaries. The Parties specifically agree and acknowledge that each Governance Participant is an intended third party beneficiary of this Agreement entitled to enforce its provisions.

9. Counterparts. This Agreement may be executed in counterparts and all such counterparts together shall be deemed to constitute a single executed original.

10. Amendment. This Agreement may not be amended except by written agreement executed by authorized representatives of the Parties.

ISO NEW ENGLAND INC.	AUTHORIZED INSTITUTION
By:	By:
______________________________	______________________________
Name:	Name:
Title:	Title:

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Confidential Market Information is provided to me pursuant to the terms and restrictions of the attached Non-Disclosure Agreement, that I have read such Non-Disclosure Agreement, and that I agree to be bound by it. In addition, I hereby certify that I am not a Competitive Duty Personnel as that term is defined in the Non-Disclosure Agreement. I understand that the contents of the Confidential Market Information, any notes or other memoranda, or any other form of information that copies or discloses Confidential Market Information shall not be disclosed to anyone other than in accordance with that Non-Disclosure Agreement.

By:

____

Title:

____

Representing:

____

Date:__________________________________

__

[NOTICE ADDRESS]

Attachment 3

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:

Accepted Electric Industry Practice, sometimes referred to as Good Utility Practice, means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric generation and transmission 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. Accepted Electric Industry Practice is not limited to a single, optimum practice method or act to the exclusion of others, but rather is intended to include practices, methods, or acts generally accepted in the region.

Adjusted Regulation Obligation is equal to a Market Participant’s total Real-Time Load Obligation ratio share of the total amount of Regulation provided that hour, adjusted for any internal bilateral transactions for Regulation.

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.

Amount Interrupted is, for purposes of the Load Response Program, the calculated difference between the Customer Baseline and the actual customer load. For generating assets, metered at the generator output, the Amount Interrupted is the generator output.

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, 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 electricity 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.

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; (iii) the sum of a Critical Peak Demand Resource's electrical energy reduction during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours less 30 minutes for each set of consecutive Real-Time Demand Resource Dispatch Hours within the same Operating Day in the month for that resource; or (iv) 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. 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; (iii) the sum of a Critical Peak Demand Resource's electrical energy output during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours for that resource less 30 minutes for each set of consecutive Real-Time Demand Resource Dispatch Hours within the same Operating Day in the month for that resource; or (iv) 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.

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 the 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); and (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).

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 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 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 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 a load serving entity's initially allocated share of the Installed Capacity Requirement, prior to any Capacity Load Obligation Bilaterals, during a Capacity Commitment Period for a Capacity Zone, as 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.

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

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 the other Covered Entities and for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the generation output level, expressed in MW, which can be reached by a Resource (from an off-line state) within 10 minutes after receiving a Dispatch Instruction or the amount of reduced consumption, expressed in MW, which can be reached by a Dispatchable Asset Related Demand within 10 minutes after receiving a Dispatch Instruction. A CLAIM10 value is required as part of a Resource's or Dispatchable Asset Related Demand's Offer Data. CLAIM10 values are established pursuant to the provisions of Section III.9.5.3.

CLAIM30 is the generation output level, expressed in MW, which can be reached by a Resource (from an off-line state) within 30 minutes after receiving a Dispatch Instruction or the amount of reduced consumption, expressed in MW, which can be reached by a Dispatchable Asset Related Demand within 30 minutes after receiving a Dispatch Instruction. A CLAIM30 value is required as part of a Resource's or Dispatchable Asset Related Demand's Offer Data. CLAIM30 values are established pursuant to the provisions of Section III.9.5.3.

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.

Commitment Offer Test is defined in Section III.A.5.8.3 of Appendix A of Market Rule 1.

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 weekly 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, for purposes of Section II of the Tariff, 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 Council; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Area, for purposes of Section III of the Tariff, is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: (i) 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); (ii) maintain scheduled interchange with other Control Areas, within the limits of Accepted Electric Industry Practice; (iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the applicable regional reliability council or the NERC; and (iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry 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 determined in accordance with Section III.13.2.4 of Market Rule 1.

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.

Critical 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 electrical usage during Demand Resource Critical Peak Hours or shift electrical usage from Demand Resource Critical Peak Hours to other hours and reduce the amount of capacity needed to deliver a comparable or acceptable level of service at those end-use customer facilities. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

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

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

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

Customer Baseline is the average aggregate hourly load, rounded to the nearest kWh, for each of the 24 hours in a day for each Load Response Program Asset participating in the Real-Time Price Response Program, and the average aggregated five-minute load, rounded to the nearest kWh, for each of the 24 hours in a day for Real-Time Demand Response Assets and Real-Time Emergency Generation Resource assets.

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~~is the sum of the hourly demand reduction amounts of the Demand Response Assets comprising 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, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(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 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 ~~Real-Time Demand Response Asset to reduce demand~~a Demand Response Resource to reduce demand.

Demand Reduction Value is the quantity of reduced demand, measured at the end-use customer meter, produced by a Demand Resource, which is calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

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

Demand Resource is a resource defined as On-Peak Demand Resources, Seasonal Peak Demand Resources, Critical 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 during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Demand Resource Critical 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 Critical Peak Hours means Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours.

Demand Resource Financial Assurance Requirement is an amount of financial assurance required from DRP-Only Customer registering a Demand Resource in the Day-Ahead Energy Market. This amount is calculated pursuant to Section VIII.A of the ISO New England Financial Assurance Policy.

Demand Resource Forecast Peak Hours means those hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and Real-Time Demand Response Resources, 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, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours by 10:00 p.m. on the day before the relevant Operating Day. Beginning on June 1, 2011, **Demand Resource Forecast Peak Hours** are those hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and 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, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours by 10:00 p.m. on the day before the next Operating Day.

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-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.E.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.8.

Demand Response Holiday is a holiday for which a Market Participant may not submit a Demand Reduction Offer for a Real-Time Demand Response Asset.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements in Section III.E.1.

Demand Response Resource Notification Time is the minimum time required from the time a Market Participant receives a Dispatch Instruction to reduce demand and the time the Demand Response Resource starts reducing demand in response to the Dispatch Instruction.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand during the resource's Demand Response Resource Start-up Time.

Demand Response Resource Startup Time is the time required from the time the resource starts reducing demand in response to a Dispatch Instruction and the time the resource achieves the demand reduction amount specified in the Dispatch Instruction.

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 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 or DRP-Only Customer 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 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 billing 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, Demand Resource Critical 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. Distributed Generation resources are not eligible for energy payments from ISO-administered energy markets. Generation resources cannot participate in the Forward Capacity Market as Demand Resources, unless they meet the definition of Distributed Generation.

DRP-Only Customer is a Market Participant that enrolls itself and/or one or more Demand Resources in the Load Response Program and that does not participate in other markets or programs of the New England Markets, provided, however, that a DRP-Only Customer may also be an FTR-Only Customer and/or an ODR-Only Customer. References in this Tariff to a Non-Market Participant demand response provider or similar phrases shall be deemed references to a DRP-Only Customer.

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 prices of 0.8 times CONE or lower, as described in Section III.13.2.3.2(d) of Market Rule 1.

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 – (average of max and min Effective Temperature of the day).

Effective Temperature is equal to dry bulb temperature – [windspeed X (65-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, for purposes of Section II of the Tariff, is an abnormal condition on the bulk power system(s) of New England and/or neighboring control areas that, if not immediately corrected, could lead to the shedding of firm electrical load. Such abnormal conditions are beyond the reasonable control and ability to avoid of the system operator of the region(s) experiencing such conditions. Such conditions could result from emergency outages of generating units, transmission lines or other equipment, or other such unforeseen circumstances such as load forecast errors.

Emergency, for purposes of Section III of the Tariff, is an abnormal system condition 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.

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.

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.

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.

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.

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.

FCM Pivotal Supplier shall mean a Lead Market Participant whose total Qualified Capacity from its Existing Capacity Resources in a Capacity Zone minus the quantity of its capacity subject to Non-Price Retirement Requests in that Capacity Zone for the current Forward Capacity Auction is greater than the difference between the total MW from qualified Existing Capacity Resources in the Capacity Zone minus the sum of the quantity of capacity subject to Non-Price Retirement Requests in that Capacity Zone plus the Local Sourcing Requirement for that Capacity Zone.

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 Critical Peak Demand Resource, Real-Time Demand Response Resource, and Real-Time Emergency Generation Resource, 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, provided, however, that an FTR-Only Customer may also be a DRP-Only Customer and/or an ODR-Only Customer. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

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

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

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

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

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

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

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

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

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

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

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

Governance Participant is defined in the Participants Agreement.

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

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

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

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

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

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

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

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

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

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

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

Hourly Real-Time Emergency Generation Resource Deviation means the difference between the Average Hourly Output of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction 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.

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.

HQ Interconnection Excess is the difference between the HQ Interconnection transfer limit as determined by the ISO and the Commission approved MW value of Hydro Quebec Interconnection Capability Credits.

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.

Hydro Quebec Interconnection Capability Credits are credits that are granted to a Market Participant or group of Market Participants in accordance with the ISO New England System Rules, where the value of such credits is determined in accordance with the ISO New England Manuals.

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, a DRP-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Payment (ICAP Payment) means the monthly payments made to ICAP Resources for installed capacity during the ICAP Transition Period.

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.

Installed Capacity Resource (ICAP Resource) means a resource that met the requirements to receive installed capacity payments during the ICAP Transition Period.

Installed Capacity Transition Period (ICAP Transition Period) is December 1, 2006 through May 31, 2010.

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.

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

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

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

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

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

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

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

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

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

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

ITC Agreement is defined in Attachment M to the OATT.

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

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

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

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

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

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

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers 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, Demand Resource Critical 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 Resource is defined in Section III.6.1 of Market Rule 1.

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.

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.

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.

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

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 and/or a DRP-Only Customer and/or an ODR-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 Generation is the maximum generation output of a ~~Real-Time Demand Response Asset comprised of Distributed Generation~~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 can deliver.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, measured at the retail delivery point of a ~~Real-Time~~ Demand Response Asset.

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

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

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

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

Measurement and Verification Reference Reports are optional reports submitted by Demand Resource suppliers during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New

England Manuals. Measurement and Verification Reference Reports update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

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

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

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

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

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

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

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

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

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

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

Minimum 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 that the ISO must commit a Demand Response Resource.

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

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

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

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

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

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

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

MUI is the market user interface.

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

MW is megawatt.

MWh is megawatt-hour.

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

NCPC Charge means the charges to Market Participants 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 Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

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.13.2.4(c) of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource (including any payment as an ICAP Resource pursuant to the market rules in effect prior to December 1, 2006 or any ICAP Payment during the ICAP Transition Period pursuant to the market rules in effect from December 1, 2006 through May 31, 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 England Control Area, for purposes of Section II of the Tariff, is the Control Area (as defined in Section II.1.11) 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 Control Area, for purposes of Section III of the Tariff, is the integrated electric power system to which a common automatic generation control scheme and various operating procedures are applied by or under the supervision of the ISO in order to: (i) match, at all times, the power output of the generators within the electric power system and capacity and energy purchased from entities outside the electric power system, with the load within the electric power system; (ii) maintain scheduled interchange with other interconnected systems, within the limits of Accepted Electric Industry Practice; (iii) maintain the frequency of the electric power system within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the NPCC and NERC; and (iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry Practice.

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

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 calculated in accordance with Section VII.B.2(i) of the ISO New England Financial Assurance Policy.

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.

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.

ODR-Only Customer is a Market Participant that registers with the ISO an Other Demand Resource (as defined in Section III.1 of this Tariff) and that does not participate in other markets or programs of the

New England Markets, provided, however, that a DRP-Only Customer may also be an FTR-Only Customer and/or an DRP-Only Customer.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand 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.

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 Demand Resource (ODR) is an installation undertaken as part of a merchant, utility, or state-sponsored program, and may include Energy Efficiency, Load Management, and Distributed Generation projects that are installed after June 16, 2006, and that result in additional and verifiable reductions in end-use customer demand on the electricity network in the New England Control Area during specified ODR performance hours of the ICAP Transition Period.

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.

Out-of-Market Capacity is certain capacity that is counted in determining whether the Alternative Capacity Price Rule applies, as described in Section III.13.2.7.8 of Market Rule 1.

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, as remitting agent for the Covered Entities.

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.

Pivotal Supplier is defined in Section III.A.5.2.2 of Appendix A of Market Rule 1.

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.

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.E.~~8~~7.

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 Load Zone or system-wide basis, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours. Beginning on June 1, 2011, "Real-Time Demand Resource Dispatch Hours" shall be defined as 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 Critical Peak Demand Resources and 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 the hours, or portions thereof, when the ISO dispatches Real-Time Demand Response Resources in the Load Zone where a Demand Resource is located in response to Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours. Beginning on June 1, 2011, Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Demand Resource Forecast Peak Hours and 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 the output of one or more emergency generators 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 to curtail electric consumption. Real-Time Emergency Generation Resources would be dispatched by the ISO on a 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. Beginning on June 1, 2011, 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 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, 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 Accepted Electric Industry 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.

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.

Re-Offer Period is the period normally between 16:00 and 18:00 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.

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.

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.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer, a DRP-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 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.

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.

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.

SPD means the ISO's Scheduling, Pricing, and Dispatch software, as more fully described in Section III.A.5.5.3 of Appendix A of Market Rule 1.

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.

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.

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.

Submitted Offer is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

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 Margin is defined in Section III.A.5.2.2 of Appendix A 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 Restoration and Planning Service is the form of Ancillary Service described in Schedule 16 of the OATT. System Restoration and Planning Service is referred to as blackstart service.

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 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 Load Zone or, starting on June 1, 2011, 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 Load Zone or, starting on June 1, 2011, 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.

UCS is Unit Commitment Software as more fully defined in Section III.A.5.5.3 of Appendix A of Market Rule 1.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

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

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

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

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

III.8 Demand Response Baselines

~~A Demand Response Baseline is calculated for any Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that requires a baseline on a daily basis using five-minute meter data.~~

~~8.1 Establishing the Initial Demand Response Baseline~~

~~The Demand Response Baseline for a new Real-Time Demand Response Asset or Real-Time Emergency Generation Asset (an asset with no previously computed Demand Response Baseline) shall be the simple average of meter data for the asset for each five-minute interval from the initial ten non-Demand Response Holiday weekdays. The initial ten non-Demand Response Holiday weekdays of meter data used to establish the Demand Response Baseline shall consist of the first ten consecutive non-Demand Response Holiday weekdays with a complete set of interval meter data. A Market Participant may not submit Demand Reduction Offers until the month following the initial establishment of a Demand Response Baseline for an asset.~~

~~8.2 Establishing the Demand Response Baseline for the Present Day~~

~~If, for a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:~~

- ~~a. the asset has been dispatched or audited in the present day pursuant to Section III.13, or;~~
- ~~b. the Demand Reduction Offer associated with the asset is eligible in the Operating Day for payments pursuant to Section III.E.9, then:~~

~~the asset's Demand Response Baseline, in each five-minute interval, for the present day is equal to the Demand Response Baseline, in the same five-minute interval from the prior day.~~

~~8.3 Establishing the Demand Response Baseline for the Next Day~~

~~If, for a Real-time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:~~

- ~~a. the asset has not been dispatched or audited in the present day pursuant to Section III.13, or;~~
- ~~b. the Demand Reduction Offer associated with the asset is not eligible in any hour of the Operating Day for payments pursuant to Section III.E.9, or;~~

~~c. the Demand Reduction Offer associated with the asset is eligible in the Operating Day for payments pursuant to Section III.E.9 and more than seven of the prior 10 non-Demand Response Holiday weekdays have a Demand Response Baseline determined pursuant to Section III.8.2, then:~~

~~the asset's Demand Response Baseline in each five-minute interval, for the next day is calculated as the sum of 0.9 times the asset's Demand Response Baseline in the same five-minute interval from the prior day and 0.1 times the asset's meter data in the same five-minute interval in the present day.~~

~~8.4 Baseline Adjustment~~

~~8.4.1 Baseline Adjustment for Real-Time Demand Reductions from Assets Without Generation~~

~~For each day the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset pursuant to Section III.E.8.1, the ISO will calculate an adjustment factor equal to the average difference (MW) between the asset's actual metered demand and its Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load.~~

~~8.4.2 Baseline Adjustment for Real-Time Demand Reductions from Assets With Generation~~

~~For each day the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset pursuant to Section III.E.8.2, the ISO will calculate an adjustment factor equal to the average difference (MW) between the sum of the asset's actual metered demand and the output of all generators located behind the asset's retail delivery point in the same time intervals and the asset's Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load, plus the output of all generators located behind the asset's retail delivery point in the same time intervals as the asset's Maximum Load.~~

~~For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset that is comprised of a Distributed Generation asset located behind the retail delivery point of an individual end-use customer facility, the asset's Demand Response Baseline shall not be subject to the baseline adjustment.~~

A Demand Response Baseline is calculated in 5-minute intervals for each Demand Response Asset for the following day types:

(a) weekdays (Monday-Friday) that are non-ISO settlement holidays;
(b) Saturdays, and;
(c) Sundays.

8.1 Demand Response Baseline Calculations

If a Demand Response Asset's metered demand represents a net supply of energy to the electrical system, the Demand Response Asset's metered demand in the interval will be set equal to zero and that zero demand value will be used in the Demand Response Baseline calculations for that interval pursuant to Sections III.8.2 and III.8.4.

8.2 Establishing an Initial Demand Response Baseline

The Demand Response Baseline for a Demand Response Asset with no previously computed Demand Response Baseline shall be the simple average of metered demand data for the asset for each five-minute interval, subject to the conditions in Section III.8.1, from the initial ten days of the same day type. The initial 10 days of meter data used to establish the Demand Response Baseline shall consist of the first 10 consecutive days of the same day type with a complete set of interval meter data. A Market Participant may not submit Demand Reduction Offers for a given day type until the month following the initial establishment of the Demand Response Baseline of the same day type for a Demand Response Asset.

8.3 Establishing a Demand Response Baseline for the Present Day

If, for a Demand Response Asset that has established an initial Demand Response Baseline, the Demand Reduction Offer of the Demand Response Resource associated with the Demand Response Asset is eligible in the Operating Day for payments pursuant to Section III.E.9, then the Demand Response Baseline of the Demand Response Asset, in each five-minute interval, for the present day is equal to the

Demand Response Baseline of that Demand Response Asset, in the same five-minute interval from the prior day of the same day type.

8.4 Establishing a Demand Response Baseline for the Next Day of the Same Day Type

If, for a Demand Response Asset that has established an initial Demand Response Baseline:

(a) the Demand Reduction Offer of the Demand Response Resource associated with the Demand Response Asset is not eligible in the Operating Day for payments pursuant to Section III.E.9, or;

(b) the Demand Reduction Offer associated with the asset is eligible in the Operating Day for payments pursuant to Section III.E.9 and more than seven of the prior 10 days of the same day type have a Demand Response Baseline determined pursuant to Section III.8.3, then:

the Demand Response Baseline of the Demand Response Asset in each five-minute interval, for the next day of the same day type, is calculated as the sum of 0.9 times the Demand Response Baseline of that Demand Response Asset in the same five-minute interval from the prior day of the same day type and 0.1 times the Demand Response Asset's meter data, subject to the conditions in Section III.8.1, in the same five-minute interval in the present day.

8.5 Baseline Adjustment

For each day that a Demand Response Resource associated with a Demand Response Asset is scheduled in the Day-Ahead Energy Market or is dispatched in Real-Time for a demand reduction amount greater than zero, the ISO will calculate an adjustment factor equal to the average difference (MW) between the Demand Response Asset's metered demand and its Demand Response Baseline in the intervals during the two-hour period beginning two hours plus the Demand Response Resource's Start-up Time prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the Demand Response Asset's Maximum Load value. For purposes of establishing the adjusted Demand Response Baseline, if a Demand Response Asset's metered demand represents a net supply of energy to the electrical grid, the Demand Response Asset's metered demand in the interval will be set equal to zero.

SECTION III

MARKET RULE 1

APPENDIX E

DEMAND RESPONSE

APPENDIX E

DEMAND RESPONSE

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APPENDIX E

DEMAND RESPONSE

~~**1. Demand Response Registration**~~

~~A Market Participant may register a Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis to provide demand reductions during hours ending 0800 through 1800 on non-Demand Response Holiday weekdays subject to the following conditions:~~

~~(a) the asset is able to produce at least 100 kW of demand reduction, and;~~

~~(b) the metering and communication equipment associated with the asset meets the requirements specified in Section III.E.2.~~

~~**1.1 Registration Parameters**~~

~~During the registration process, Market Participants must submit the following information for each Real-Time Demand Response Asset:~~

~~(a) Maximum Interruptible Capacity;~~

~~(b) Maximum Load, and;~~

~~(c) Maximum Generation, for Real-Time Demand Response Assets that are comprised of Distributed Generation.~~

~~**1.2 Restrictions on Real-Time Demand Response Asset Registration**~~

~~A Market Participant may not register and must retire if previously registered a Real-Time Demand Response Asset that is comprised of:~~

~~(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;~~

~~(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.~~

~~A Market Participant may not register an existing Generator Asset as a Real-Time Demand Response Asset for the purpose of submitting Demand Reduction Offers.~~

~~2. Metering and Communication~~

~~2.1 Interval Metering and Telemetry Requirements~~

~~The actual metered demand of each individual end-use customer facility that comprises a Real-Time Demand Response Asset must be measured using interval meters located at the individual end-use customer's retail delivery point and shall be reported to the ISO at an interval of five minutes. Actual metered demand submitted to the ISO shall not include average avoided peak distribution losses. Each generator located behind an individual end-use customer's retail delivery point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.~~

~~Interval meters required pursuant to Section III.E.2.1 must meet the following requirements:~~

~~(a) the interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes or less;~~

~~(b) if the interval meter is the same meter used by the distribution company for billing purposes, the meter is a revenue-quality meter that is accurate within ± 0.5%, and;~~

~~(c) if the interval meter is not the same meter used by the distribution company for billing purposes, the interval meter is either a revenue-quality meter that is accurate within ± 0.5% or a non-revenue-quality meter with an overall accuracy of ± 2.0%. For each non-revenue-quality meter used, the Market Participant must, during the registration process, submit certification from the meter~~

~~manufacturer that the interval meter being used meets the ± 2.0% accuracy threshold, and shall specify accuracy for the following parameters:~~

i. ~~current measurement;~~

ii. ~~voltage measurement;~~

iii. ~~A/D conversion, and;~~

iv. ~~calibration.~~

~~2.2 Meter Testing~~

~~All interval meters must be periodically tested and calibrated.~~

~~Market Participants must conduct periodic meter data validation checks.~~

~~Market Participants must repair or replace meters that are found to be inaccurate pursuant to periodic testing and data validation checks.~~

~~Market Participants must perform an annual independent certification of the accuracy and precision of the meters and meter data communication systems.~~

~~2.3 Auditing~~

~~The ISO may, for a Real-Time Demand Response Asset, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and measurement equipment, and witness the demand reduction activities of any facility associated with the asset.~~

~~Market Participants must make retail billing meter data from the Host Participant for the facilities associated with a Real-Time Demand Response Asset available to the ISO upon request.~~

~~Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing, and certifying the metering, data recording and measurement equipment of Real-Time Demand Response Assets.~~

~~2.4 Communication/Telemetry~~

~~Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facilities comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area.~~

~~For Real-Time Demand Response Assets whose demand reductions are not achieved by Distributed Generation but where there is a generator located behind the retail delivery point, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of all generation.~~

~~For Real-Time Demand Response Assets whose demand reductions are achieved by Distributed Generation, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of Distributed Generation associated with the Real-Time Demand Response Asset.~~

~~3. Demand Reduction Offers~~

~~3.1 Required Demand Reduction Offer Parameters~~

~~Market Participants must submit a Demand Reduction Offer for each Real-Time Demand Response Asset that meets the requirements of this section in order to be eligible for a demand reduction payment.~~

~~A Demand Reduction Offer must be equal to or greater than the Demand Reduction Threshold Price in effect on the day the Demand Reduction Offer is made.~~

~~Demand Reduction Offers reflect the amount of demand reduction offered at the retail delivery point excluding transmission and distribution losses.~~

~~A Demand Reduction Offer shall consist of a single offer price in $/MWh (less than or equal to $1000/MWh) and a single demand reduction amount (in MW to the nearest 0.1 MW) that shall apply to hours ending 0800 through 1800 in the Operating Day.~~

~~A Market Participant may submit a single Demand Reduction Offer for each of its Real-Time Demand Response Assets for each Operating Day that is a non-Demand Response Holiday weekday.~~

~~Demand Reduction Offers for the following Operating Day must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the Operating Day and may not be changed thereafter.~~

~~The minimum Demand Reduction Offer amount for each Real-Time Demand Response Asset is 100 kW.~~

~~The maximum Demand Reduction Offer amount for each Real-Time Demand Response Asset cannot exceed the asset's Maximum Interruptible Capacity.~~

~~3.2 Optional Demand Reduction Offer Parameters~~

~~A Demand Reduction Offer may specify a minimum interruption duration of one to four hours. If a Market Participant does not specify a minimum interruption duration in its Demand Reduction Offer, the minimum interruption duration shall be one hour.~~

~~A Demand Reduction Offer may specify a curtailment initiation price (in $ per interruption). If a Market Participant does not specify a curtailment initiation price, the curtailment initiation price shall be $0.~~

~~A Demand Reduction Offer must meet the following minimum and maximum price requirements:~~

~~(a) The offer price not including the curtailment initiation price shall be greater than or equal to the Demand Reduction Threshold Price; and~~

~~(b) The offer cost of the Demand Reduction Offer, which shall include the curtailment initiation price, shall be less than or equal to $1000/MWh. The offer cost shall be computed as follows: offer cost = offer price + [curtailment initiation price/(minimum interruption duration x bid amount (MW))].~~

~~4. Day-Ahead Clearing, Scheduling and Notification~~

~~Demand Reduction Offers are cleared after the Day-Ahead Energy Market results are determined. Demand Reduction Offers are cleared by comparing the Demand Reduction Offer to the hourly Day-Ahead LMPs for the Load Zone in which the Real-Time Demand Response Asset is located. A Demand Reduction Offer associated with a Real-Time Demand Response Asset will clear in one or more hours of the Operating Day if the sum of the hourly Day-Ahead LMP times the Demand Reduction Offer amount in the cleared hours of the Operating Day is greater than or equal to the sum of the curtailment initiation price for the Operating Day and the sum of the Demand Reduction Offer price times the Demand Reduction Offer amount in the cleared hours of the Operating Day.~~

~~The ISO will provide Market Participants with demand curtailment schedules for Real-Time Demand Response Assets based on cleared Demand Reduction Offers.~~

~~The demand curtailment schedule shall reflect demand reductions (MW) at the Real-Time Demand Response Asset's retail delivery point.~~

~~5. Real-Time Scheduling of Demand Reductions~~

~~A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for the next Operating Day pursuant to Section III.E.4. If a Market Participant's Demand Reduction Offer is not cleared Day-Ahead to reduce demand in an hourly time interval for the next Operating Day, the Market Participant may initiate a Real-Time demand reduction by reducing demand when the offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which a Real-Time Demand Response Asset is located.~~

~~A Market Participant will not receive a Dispatch Instruction in Real-Time for a Real-Time Demand Response Asset.~~

~~5.1 Requirements for Demand Reductions of 5 MW and Above~~

~~A Market Participant with a Real-Time Demand Response Asset that has submitted a Demand Reduction Offer for the Operating Day, must request permission from the ISO prior to reducing demand in an amount greater than or equal to 5 MW during a 60 minute period, unless the asset was dispatched or audited pursuant to Section III.13. Permission must be requested not less than 15 minutes and not greater than 60 minutes before the start of the demand reduction. The ISO may approve or deny the requested interruption based on the impact of the interruption on system reliability.~~

~~6. Determination of the Demand Reduction Threshold Price~~

~~The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data for the same month of the previous year. The ISO may adjust the offer data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:~~

i. ~~Each generator and import offer block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.~~

ii. ~~An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer block.~~

iii. ~~A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.~~

iv. ~~A historic threshold price~~ $\cancel{P_{th}}$ ~~shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from demand response exceeds the cost to load associated with compensating demand response.~~

v. ~~The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:~~

$$\cancel{DRTP = P_{th} \times \frac{FPI_c}{FPI_h}}$$

~~where FPI_h is the Forward Reserve Fuel Index for the same month of the previous year, and FPI_c is the Forward Reserve Fuel Index for the current month.~~

~~The ISO will post the resulting Demand Reduction Threshold Price on its website in advance of the Demand Reduction Threshold Price's effective date.~~

~~The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Real-Time Demand Response Assets located anywhere within the New England Control Area.~~

~~7. Demand Response Baselines~~

~~A Market Participant must establish a Demand Response Baseline pursuant to Section III.8 prior to submitting a Demand Reduction Offer for a Real-Time Demand Response Asset.~~

~~A Market Participant shall take no actions to establish a Demand Response Baseline or affect a Demand Response Baseline adjustment that results in a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers absent demand reduction payments.~~

~~For Real-Time Demand Response Assets comprised of Distributed Generation, a Market Participant shall take no actions to establish a Demand Response Baseline that results in a Demand Response Baseline that reduces the expected output levels of its generation absent demand reduction payments.~~

~~8. Real-Time Demand Reduction Obligations~~

~~8.1 Real-Time Demand Reduction of Assets Without Generation~~

~~The Real-Time demand reduction amount of a Real-Time Demand Response Asset is equal to the difference between its Demand Response Baseline adjusted pursuant to Section III.8.4 and the asset's Real-Time metered demand, during the intervals that the Real-Time Demand Response Asset was scheduled Day-Ahead by the ISO to reduce demand or was otherwise eligible to receive payment for a demand reduction in Real-Time. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered demand is greater than its adjusted Demand Response Baseline.~~

~~8.2 Real-Time Demand Reduction of Assets With Generation~~

~~To the extent a generator is located behind the retail delivery point of an individual end-use customer facility that comprises a Real-Time Demand Response Asset, the metered output of the generator in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline. The Real-Time demand reduction amount achieved by the individual end-use customer facility that comprises a Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval minus the sum of the metered demand measured at the retail delivery point and the output of all of the generators located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of all of the generators is greater than its adjusted Demand Response Baseline.~~

~~If a Real-Time Demand Response Asset is comprised of a Distributed Generation asset located behind the retail delivery point of an individual end-use customer facility, the interval metered output of the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be used to determine its Demand Response Baseline. The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be equal to the asset's incremental output in each five-minute interval relative to its Demand Response Baseline in the same intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered output is less than its Demand Response Baseline.~~

~~8.3 Treatment of Net Supply~~

~~If the metered amount measured at the retail delivery point reflects net energy supply during intervals in which Real-Time Demand Response Assets and/or Real-Time Emergency Generation Assets behind the retail delivery point had positive Real-Time demand reductions, then the amount of net energy supplied in an interval with a positive Real-Time demand reduction shall be subtracted from the Real-Time demand reduction amount in the same interval of each Real-Time Demand Response Asset and/or Real-Time Emergency Generation Asset behind that retail delivery point on a *pro rata* basis. The adjustment for net energy supply shall not result in a negative Real-Time demand reduction amount.~~

~~8.4 Real-Time Demand Reduction Obligations~~

~~The Real-Time Demand Reduction Obligation of a Real-Time Demand Response Asset is equal to its Real-Time demand reduction amount adjusted for net supply (limited to 200% of the associated Demand Reduction Offer amount) multiplied by one plus the percent average avoided peak distribution losses.~~

~~9. Settlement~~

~~9.1 Day-Ahead Settlement~~

~~A Market Participant with a Real-Time Demand Response Asset will be paid for its Day-Ahead Demand Reduction Obligation multiplied by the Day-Ahead LMP for the Load Zone within which the Real-Time Demand Response Asset is located.~~

~~9.2 Real-Time Settlement~~

~~9.2.1. Real-Time Demand Response Assets with Cleared Demand Reduction Offers~~

~~A Market Participant with a Real-Time Demand Response Asset will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the final hourly Real-Time LMP for the Load Zone within which the Real-Time Demand Response Asset is located. The payment for the amount by which the Real-Time Demand Reduction Obligation exceeds the Day-Ahead Demand Reduction Obligation in an hour shall be set to zero if the provisional Real-Time LMP for that hour is less than the Demand Reduction Threshold Price.~~

~~A Market Participant will not be charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E.5.1.~~

~~9.2.2. Real-Time Demand Response Assets without Cleared Demand Reduction Offers~~

~~If the Demand Reduction Offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which the~~

~~Real-Time Demand Response Asset is located, the Market Participant will be paid the final hourly Real-Time LMP multiplied by its Real-Time Demand Reduction Obligation.~~

~~A Market Participant will not be charged pursuant to Section III.E.9.2.2 if:~~

~~(a) a Demand Reduction Offer does not clear Day-Ahead pursuant to Section III.E.4, and;~~

~~(b) the Real-Time Demand Response Asset produces a negative Real-Time demand reduction amount.~~

~~A Market Participant will not be paid for a Real-Time Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E.5.1.~~

~~9.3 Cost Allocation~~

~~Payments and charges pursuant to this section will be allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes or incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.~~

~~10. Average Distribution Losses~~

~~For purposes of Section III.E, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.~~

1. Demand Response Registration

1.1 Demand Response Resource Registration

A Market Participant may register a Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis for non-ISO settlement holidays subject to the following conditions:

(a) each Demand Response Resource must be a single Demand Response Asset or an aggregation of Demand Response Assets located within the same Dispatch Zone;

(b) each Demand Response Resource must be able to produce at least 100 kW of demand reduction, and;

(c) the Market Participant must comply with ISO required auditing and testing requirements.

A Market Participant may not register a Real-Time Emergency Generation Resource, an On-Peak Demand Resource, a Seasonal Peak Demand Resource or a Dispatchable Asset Related Demand to participate as a Demand Response Resource in the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant may not register an existing Generator Asset as a Demand Response Asset for the purpose of submitting Demand Reduction Offers.

1.2 Demand Response Asset Registration

A Market Participant may register a Demand Response Asset subject to the following conditions:

(a) Unless it meets the conditions for aggregation in sub-section (b) below, a Demand Response Asset must have a defined, single retail delivery point and be registered at a single Node.

(b) A Demand Response Asset may be the aggregate consumption of multiple end-use customers from multiple delivery points within a single Dispatch Zone if (i) the demand reduction from each retail delivery point in the aggregation is less than 10 kW, and (ii) the demand at the multiple retail delivery points satisfy the criteria for a homogenous population. A Demand Response Asset that meets these conditions for aggregation must be registered at the Dispatch Zone rather than the Node.

(c) No more than one Demand Response Asset may be located at a single retail delivery point.

(d) Each Demand Response Asset must be mapped to a Demand Response Resource.

(e) Each Demand Response Asset must be able to produce at least 10 kW of demand reduction.

(f) A Demand Response Asset with the ability to offer a demand reduction equal to or greater than 5 MW from the same retail delivery point must be registered as a single Demand Response Resource at a Node.

(g) The metering and communication equipment associated with each Demand Response Asset must meet the requirements in Section III.E.2.

During the registration process, Market Participants must submit the following for each Demand Response Asset:

(a) Maximum Interruptible Capacity;

(b) Maximum Load;

(c) Maximum Generation, for Demand Response Resources that are comprised of Distributed Generation, and;

(d) retail account number and meter number for the end use customer.

1.3 Restrictions on Demand Response Resource Registration

A Market Participant may not register and must retire if previously registered a Demand Response Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

2. Metering and Communication

2.1 Interval Metering and Telemetry Requirements

The metered demand of each individual end-use customer facility that comprises a Demand Response Asset must be measured using interval meters located at the individual end-use customer's retail delivery point and shall be reported to the ISO at an interval of five minutes. Metered demand data submitted to the ISO shall not include average avoided peak distribution losses. Each generator located behind an individual end-use customer's retail delivery point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.

The interval meters required pursuant to Section III.E.2.1 must meet the following requirements:

(a) The interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes or less;

(b) If the interval meter is the same meter used by the distribution company for billing purposes, the meter is a revenue-quality meter that is accurate within ± 0.5%; and

(c) If the interval meter is not the same meter used by the distribution company for billing purposes, the interval meter is either a revenue-quality meter that is accurate within ± 0.5% or a non-revenue-quality meter with an overall accuracy of ± 2.0%. For each non-revenue-quality meter used, the Market Participant must, during the registration process, submit certification from the meter manufacturer that the interval meter being used meets the ± 2.0% accuracy threshold, and shall specify accuracy for the following parameters:

i. current measurement;

ii. voltage measurement;

iii. A/D conversion; and

iv. calibration.

2.2 Communication/Telemetry

The Market Participant must utilize a remote terminal unit for communicating telemetry and receiving dispatch instructions from the ISO.

Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facilities that comprise the Demand Response Asset on the electricity network in the New England Control Area.

For Demand Response Assets whose demand reductions are not achieved by Distributed Generation but where there is a generator located behind the retail delivery point, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility that comprises the Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of all generation.

For Demand Response Assets whose demand reductions are achieved by Distributed Generation, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility that comprises the Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of Distributed Generation associated with the Demand Response Asset.

2.3 Meter Testing

All interval meters must be periodically tested and calibrated.

Market Participants must conduct periodic meter data validation checks.

Market Participants must repair or replace meters that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters and meter data communication systems.

2.4 Auditing

The ISO may, for Demand Response Resources, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and measurement equipment, and witness the demand reduction activities of any facility associated with a Demand Response Asset.

Market Participants must make retail billing meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing and certifying the metering, data recording and measurement equipment of Demand Response Assets.

3. Day-Ahead Energy Market Demand Reduction Offers

Market Participants must submit a Demand Reduction Offer for each Demand Response Resource that meets the requirements of this section in order to be eligible for a demand reduction payment.

The Market Participant's Demand Reduction Offer for a Demand Response Resource must satisfy the following conditions:

(a) Demand Reduction Offers must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the applicable Operating Day.

(b) The Market Participant can submit up to 10 monotonically increasing price/demand reduction amount pairs for each Operating Day. The demand reduction amount shall not include an adjustment for average avoided peak transmission and distribution losses.

(c) The minimum amount for each price/demand reduction amount pair of a Demand Reduction Offer is 100 kW.

(d) The sum of all price/demand reduction amount pairs for a Demand Reduction Offer cannot exceed the sum of the Maximum Interruptible Capacities of the resource's Demand Response Assets.

(e) The minimum Demand Reduction Offer price must be equal to or greater than the Demand Reduction Threshold Price in effect for the day the Demand Reduction Offer is submitted.

(f) The maximum Demand Reduction Offer price must be less than or equal to $1000/MWh.

Market Participants may not Self-Schedule interruptions in the Day-Ahead Energy Market.

3.1 Required Demand Reduction Offer Parameters

The Market Participant shall provide the following hourly values in its Demand Reduction Offer. The Market Participant shall maintain up-to-date values for each of these parameters prior to and throughout the Operating Day:

(a) Available or Unavailable;

(b) Minimum Reduction (MW), and;

(c) Maximum Reduction (MW).

3.2 Optional Demand Reduction Offer Parameters

The Market Participant may also specify the following in its Demand Reduction Offer:

(a) Interruption Cost ($)

(b) Minimum Reduction Time (Hrs)

(c) Minimum Time Between Reductions (Hrs)

(d) Demand Response Resource Startup Time (Hrs)

(e) Demand Response Resource Notification Time (Hrs)

(f) Demand Response Resource Ramp Rate (MW/min)

~~**Demand Response Resources with a Capacity Supply Obligation in the Forward Capacity Market**~~

~~A Demand Response Resource with a Capacity Supply Obligation in the current Obligation Month is required to submit a Demand Reduction Offer in the Day-Ahead Energy Market for each hour of every day of the Obligation Month.~~

~~The minimum Demand Reduction Offer amount for a Demand Response Resource with a Capacity Supply Obligation must be greater than or equal to the Demand Response Resource's Net Capacity Supply Obligation for the current Obligation Month.~~

~~A Demand Response Resource with demand reduction capability greater than the Demand Response Resource's Net Capacity Supply Obligation in the current Obligation Month may submit Demand Reduction Offers in the Day-Ahead Energy Market for the demand reduction capability that is greater than the Net Capacity Supply Obligation for the current Obligation Month.~~

4. Real-Time Energy Market Demand Reduction Offers

During the re-offer period, Market Participants may submit revisions to the price or demand reduction amount parameters of a Demand Reduction Offer. Demand Response Resources scheduled subsequent to the closing of the re-offer period shall be settled at the applicable Real-Time Prices.

Revisions to Demand Reduction Offers during the re-offer period are subject to the following conditions that apply to Day-Ahead Demand Reduction Offers under Section III.E.3: limitation to 10 monotonically increasing price/demand reduction amount pairs, minimum amount, maximum amount, minimum price and maximum price.

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for that Operating Day pursuant to Section III.E.5 or modified during the re-offer period.

No changes will be allowed to the Demand Reduction Offer after the close of the re-offer period.

Market Participants may not Self-Schedule interruptions in the Real-Time Energy Market.

5. Scheduling and Dispatching

The ISO shall schedule in the Day-Ahead Energy Market and commit and dispatch in the Real-Time Energy Market the Demand Response Resource based on:

(a) least-cost, security-constrained dispatch and commitment as specified in Section III.1.7.6(a); and

(b) the Demand Reduction Offer for the Demand Response Resource, with demand reduction amounts adjusted by average avoided peak distribution losses.

At the conclusion of the Day-Ahead Energy Market clearing, the ISO will provide Market Participants with Day-Ahead demand reduction schedules for Demand Response Resources reflecting demand reduction amounts that do not include average avoided peak transmission and distribution losses for each hour of the following Operating Day.

During the Operating Day, the ISO will issue Dispatch Instructions to the Market Participant specifying the expected demand reduction amount that does not include average avoided peak transmission and distribution losses from their Demand Response Resource and the Dispatch Rate.

A Market Participant must notify the ISO, as soon as practicable, of a facility shutdown or equipment outage (including partial outages) that reduces the Demand Response Resource's ability to achieve the demand reduction reflected in the Demand Reduction Offer for an Operating Day.

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data for the same month of the previous year. The ISO may adjust the offer data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

(a) Each generator and import offer block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer block.

(c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

(d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from demand response exceeds the cost to load associated with compensating demand response.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

~~(a)~~

$$DRTP = P_{th} \times \frac{FPI_c}{FPI_h}$$

where FPI_h is the Forward Reserve Fuel Index for the same month of the previous year, and FPI_c is the Forward Reserve Fuel Index for the current month.

The ISO will post the resulting Demand Reduction Threshold Price on its website in advance of the Demand Reduction Threshold Price's effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Demand Response Resources located anywhere within the New England Control Area.

7. Real-Time Demand Reduction Obligation

A Demand Response Resource's Real-Time Demand Reduction Obligation will be calculated for each dispatch interval in which the Demand Response Resource receives a Dispatch Instruction to reduce demand.

7.1 Real-Time Demand Reductions

The Real-Time demand reduction in a dispatch interval is the difference between the adjusted Demand Response Baseline and the metered demand for each Demand Response Asset associated with the Demand Response Resource.

If a Market Participant receives a Dispatch Instruction for a Demand Response Resource to reduce demand in a dispatch interval by zero MW, then in calculating the Real-Time Demand Reduction Obligation of the Demand Response Resource the Real-Time demand reductions of the Demand Response Assets comprising the resource shall be equal to zero for that dispatch interval.

7.2 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Demand Response Resource is the sum of the hourly integrated Real-Time demand reduction amounts of the Demand Response Assets comprising the Demand Response Resource, multiplied by one plus the percent average avoided peak distribution losses. In calculating the Real-Time Demand Reduction Obligation of a Demand Response Resource, the Real-Time demand reduction amounts of the Demand Response Assets comprising the resource shall be adjusted for net supply as specified in Section III.E.7.3 below.

If a Market Participant fails to comply with the metering and communication requirements in Section III.E.2 for a Demand Response Resource for any period of time, then the Real-Time Demand Reduction Obligation shall be zero for that period of time.

7.3 Treatment of Net Supply

If a Demand Response Asset's metered demand represents a net supply of energy to the electrical grid, the Demand Response Asset's metered demand in the interval will be set equal to zero and that value will be used in establishing the Real-Time Demand Reduction Obligation.

To the extent a Real-Time Emergency Generation Asset is located behind the retail delivery point of an individual end-use customer facility that comprises a Demand Response Asset and the Real-Time Emergency Generation Resource associated with the Real-Time Emergency Generation Asset is dispatched or audited pursuant to Section III.13, the metered output of the Real-Time Emergency Generation Asset, in each five-minute interval, shall be added to the metered demand measured at the retail delivery point in the same intervals for purposes of determining:

(a) a Demand Response Asset's Demand Response Baseline, and;

(b) the Real-Time demand reduction achieved by the individual end-use customer facility that comprises the Demand Response Asset.

8. Demand Response Resource Baseline

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8 prior to submitting a Demand Reduction Offer for a Demand Response Resource.

A Market Participant shall not take actions to create or maintain a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers in the absence of demand reduction payments.

9. Energy Market Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Demand Response Resource will be paid for its Day-Ahead Demand Reduction Obligation multiplied by the Day-Ahead LMP for the Dispatch Zone or Node at which the resource is registered.

9.2 Real-Time Settlement

A Market Participant with a Demand Response Resource will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the hourly Real-Time LMP for the Dispatch Zone or Node at which the resource is registered.

~~Dispatch or Audit Pursuant to Section III.13~~

~~A Market Participant with a Demand Response Resource that is not eligible for payment pursuant to Sections III.E.9.1 or III.E.9.2 that is dispatched or audited pursuant to Section III.13 will be paid or charged the applicable Real-Time LMP multiplied by its Real-Time Demand Reduction Obligation determined, as applicable, for the Real-Time Demand Response Event Hours or the audit dispatch period.~~

~~Real-Time Emergency Generation~~

~~A Market Participant with a Real-Time Emergency Generation Resource in the Forward Capacity Market will be paid for a demand reduction, adjusted by average avoided peak distribution losses, at the applicable Real-Time LMP for the Dispatch Zone in which the Real-Time Emergency Generation Resource is located when dispatched for Real-Time Emergency Generation Event Hours or audited pursuant to Section III.13.~~

9.3 Cost Allocation

Charges or payments resulting from Real-Time demand reductions produced by Demand Response Resources or Real-Time Emergency Generation Resources shall be allocated on an hourly basis proportionally to Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

9.4 NCPC Credits and Charges

A Market Participant with a Demand Response Resource is eligible for NCPC credits if the resource is following Dispatch Instructions. A Market Participant with a Demand Response Resource is ineligible for NCPC credits and may be assessed NCPC charges if the resource is not operating within the acceptable dispatch tolerance. A resource is not operating within the acceptable dispatch tolerance if in any five-minute interval for an hour the resource is not operating within 10% above or below the resource's Dispatch Instruction, except that a Market Participant with a resource that is not operating within the acceptable dispatch tolerance will not be assessed NCPC charges if during the entire hour the resource operates within 5% above or below the resource's Dispatch Instruction.

10. Average Avoided Peak Distribution Losses

For purposes of Section III.E, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

Attachment 4

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:

Accepted Electric Industry Practice, sometimes referred to as Good Utility Practice, means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric generation and transmission 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. Accepted Electric Industry Practice is not limited to a single, optimum practice method or act to the exclusion of others, but rather is intended to include practices, methods, or acts generally accepted in the region.

Adjusted Regulation Obligation is equal to a Market Participant’s total Real-Time Load Obligation ratio share of the total amount of Regulation provided that hour, adjusted for any internal bilateral transactions for Regulation.

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.

Amount Interrupted is, for purposes of the Load Response Program, the calculated difference between the Customer Baseline and the actual customer load. For generating assets, metered at the generator output, the Amount Interrupted is the generator output.

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, 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 electricity 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.

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; (iii) the sum of a Critical Peak Demand Resource's electrical energy reduction during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours less 30 minutes for each set of consecutive Real-Time Demand Resource Dispatch Hours within the same Operating Day in the month for that resource; or (iv) 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. 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; (iii) the sum of a Critical Peak Demand Resource's electrical energy output during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours for that resource less 30 minutes for each set of consecutive Real-Time Demand Resource Dispatch Hours within the same Operating Day in the month for that resource; or (iv) 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.

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 the 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); and (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).

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 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 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 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 a load serving entity's initially allocated share of the Installed Capacity Requirement, prior to any Capacity Load Obligation Bilaterals, during a Capacity Commitment Period for a Capacity Zone, as 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.

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

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 the other Covered Entities and for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the generation output level, expressed in MW, which can be reached by a Resource (from an off-line state) within 10 minutes after receiving a Dispatch Instruction or the amount of reduced consumption, expressed in MW, which can be reached by a Dispatchable Asset Related Demand within 10 minutes after receiving a Dispatch Instruction. A CLAIM10 value is required as part of a Resource's or Dispatchable Asset Related Demand's Offer Data. CLAIM10 values are established pursuant to the provisions of Section III.9.5.3.

CLAIM30 is the generation output level, expressed in MW, which can be reached by a Resource (from an off-line state) within 30 minutes after receiving a Dispatch Instruction or the amount of reduced consumption, expressed in MW, which can be reached by a Dispatchable Asset Related Demand within 30 minutes after receiving a Dispatch Instruction. A CLAIM30 value is required as part of a Resource's or Dispatchable Asset Related Demand's Offer Data. CLAIM30 values are established pursuant to the provisions of Section III.9.5.3.

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.

Commitment Offer Test is defined in Section III.A.5.8.3 of Appendix A of Market Rule 1.

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 weekly 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, for purposes of Section II of the Tariff, 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 Council; and
(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Area, for purposes of Section III of the Tariff, is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: (i) 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); (ii) maintain scheduled interchange with other Control Areas, within the limits of Accepted Electric Industry Practice; (iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the applicable regional reliability council or the NERC; and (iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry 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 determined in accordance with Section III.13.2.4 of Market Rule 1.

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.

Critical 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 electrical usage during Demand Resource Critical Peak Hours or shift electrical usage from Demand Resource Critical Peak Hours to other hours and reduce the amount of capacity needed to deliver a comparable or acceptable level of service at those end-use customer facilities. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

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

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

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

Customer Baseline is the average aggregate hourly load, rounded to the nearest kWh, for each of the 24 hours in a day for each Load Response Program Asset participating in the Real-Time Price Response Program, and the average aggregated five-minute load, rounded to the nearest kWh, for each of the 24 hours in a day for Real-Time Demand Response Assets and Real-Time Emergency Generation Resource assets.

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 the sum of the hourly demand reduction amounts of the Demand Response Assets comprising 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, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(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 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 Demand Response Resource to reduce demand.

Demand Reduction Value is the quantity of reduced demand, measured at the end-use customer meter, produced by a Demand Resource, which is calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

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

Demand Resource is a resource defined as On-Peak Demand Resources, Seasonal Peak Demand Resources, Critical 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 during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Demand Resource Critical 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 Critical Peak Hours means Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours.

Demand Resource Financial Assurance Requirement is an amount of financial assurance required from DRP-Only Customer registering a Demand Resource in the Day-Ahead Energy Market. This amount is calculated pursuant to Section VIII.A of the ISO New England Financial Assurance Policy.

Demand Resource Forecast Peak Hours means those hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and Real-Time Demand Response Resources, 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, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours by 10:00 p.m. on the day before the relevant Operating Day. Beginning on June 1, 2011, **Demand Resource Forecast Peak Hours** are those hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and 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, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours by 10:00 p.m. on the day before the next Operating Day.

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-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.E.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.8.

Demand Response Holiday is a holiday for which a Market Participant may not submit a Demand Reduction Offer for a Real-Time Demand Response Asset.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements in Section III.E.1.

Demand Response Resource Notification Time is the minimum time required from the time a Market Participant receives a Dispatch Instruction to reduce demand and the time the Demand Response Resource starts reducing demand in response to the Dispatch Instruction.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand during the resource's Demand Response Resource Start-up Time.

Demand Response Resource Startup Time is the time required from the time the resource starts reducing demand in response to a Dispatch Instruction and the time the resource achieves the demand reduction amount specified in the Dispatch Instruction.

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 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 or DRP-Only Customer 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 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 billing 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, Demand Resource Critical 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. Distributed Generation resources are not eligible for energy payments from ISO-administered energy markets. Generation resources cannot participate in the Forward Capacity Market as Demand Resources, unless they meet the definition of Distributed Generation.

DRP-Only Customer is a Market Participant that enrolls itself and/or one or more Demand Resources in the Load Response Program and that does not participate in other markets or programs of the New England Markets, provided, however, that a DRP-Only Customer may also be an FTR-Only Customer and/or an ODR-Only Customer. References in this Tariff to a Non-Market Participant demand response provider or similar phrases shall be deemed references to a DRP-Only Customer.

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 prices of 0.8 times CONE or lower, as described in Section III.13.2.3.2(d) of Market Rule 1.

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 – (average of max and min Effective Temperature of the day).

Effective Temperature is equal to dry bulb temperature – [windspeed X (65-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, for purposes of Section II of the Tariff, is an abnormal condition on the bulk power system(s) of New England and/or neighboring control areas that, if not immediately corrected, could lead to the shedding of firm electrical load. Such abnormal conditions are beyond the reasonable control and ability to avoid of the system operator of the region(s) experiencing such conditions. Such conditions could result from emergency outages of generating units, transmission lines or other equipment, or other such unforeseen circumstances such as load forecast errors.

Emergency, for purposes of Section III of the Tariff, is an abnormal system condition 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.

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.

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.

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.

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.

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.

FCM Pivotal Supplier shall mean a Lead Market Participant whose total Qualified Capacity from its Existing Capacity Resources in a Capacity Zone minus the quantity of its capacity subject to Non-Price Retirement Requests in that Capacity Zone for the current Forward Capacity Auction is greater than the difference between the total MW from qualified Existing Capacity Resources in the Capacity Zone minus the sum of the quantity of capacity subject to Non-Price Retirement Requests in that Capacity Zone plus the Local Sourcing Requirement for that Capacity Zone.

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 Critical Peak Demand Resource, Real-Time Demand Response Resource, and Real-Time Emergency Generation Resource, 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, provided, however, that an FTR-Only Customer may also be a DRP-Only Customer and/or an ODR-Only Customer. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

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

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

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

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

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

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

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

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

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

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

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

Governance Participant is defined in the Participants Agreement.

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

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

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

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

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

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

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

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

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

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

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

Hourly Real-Time Emergency Generation Resource Deviation means the difference between the Average Hourly Output of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction 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.

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.

HQ Interconnection Excess is the difference between the HQ Interconnection transfer limit as determined by the ISO and the Commission approved MW value of Hydro Quebec Interconnection Capability Credits.

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.

Hydro Quebec Interconnection Capability Credits are credits that are granted to a Market Participant or group of Market Participants in accordance with the ISO New England System Rules, where the value of such credits is determined in accordance with the ISO New England Manuals.

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, a DRP-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Payment (ICAP Payment) means the monthly payments made to ICAP Resources for installed capacity during the ICAP Transition Period.

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.

Installed Capacity Resource (ICAP Resource) means a resource that met the requirements to receive installed capacity payments during the ICAP Transition Period.

Installed Capacity Transition Period (ICAP Transition Period) is December 1, 2006 through May 31, 2010.

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.

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

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

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

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

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

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

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

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

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

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

ITC Agreement is defined in Attachment M to the OATT.

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

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

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

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

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

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

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers 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, Demand Resource Critical 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 Resource is defined in Section III.6.1 of Market Rule 1.

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.

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.

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.

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

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 and/or a DRP-Only Customer and/or an ODR-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 Generation is 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 Demand Response Asset can deliver.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, measured at the retail delivery point of a Demand Response Asset.

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

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

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

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

Measurement and Verification Reference Reports are optional reports submitted by Demand Resource suppliers during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New

England Manuals. Measurement and Verification Reference Reports update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

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

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

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

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

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

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

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

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

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

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

Minimum 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 that the ISO must commit a Demand Response Resource.

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

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

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

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

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

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

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

MUI is the market user interface.

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

MW is megawatt.

MWh is megawatt-hour.

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

NCPC Charge means the charges to Market Participants 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 Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

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.13.2.4(c) of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource (including any payment as an ICAP Resource pursuant to the market rules in effect prior to December 1, 2006 or any ICAP Payment during the ICAP Transition Period pursuant to the market rules in effect from December 1, 2006 through May 31, 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 England Control Area, for purposes of Section II of the Tariff, is the Control Area (as defined in Section II.1.11) 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 Control Area, for purposes of Section III of the Tariff, is the integrated electric power system to which a common automatic generation control scheme and various operating procedures are applied by or under the supervision of the ISO in order to: (i) match, at all times, the power output of the generators within the electric power system and capacity and energy purchased from entities outside the electric power system, with the load within the electric power system; (ii) maintain scheduled interchange with other interconnected systems, within the limits of Accepted Electric Industry Practice; (iii) maintain the frequency of the electric power system within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the NPCC and NERC; and (iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry Practice.

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

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 calculated in accordance with Section VII.B.2(i) of the ISO New England Financial Assurance Policy.

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.

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.

ODR-Only Customer is a Market Participant that registers with the ISO an Other Demand Resource (as defined in Section III.1 of this Tariff) and that does not participate in other markets or programs of the

New England Markets, provided, however, that a DRP-Only Customer may also be an FTR-Only Customer and/or an DRP-Only Customer.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand 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.

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 Demand Resource (ODR) is an installation undertaken as part of a merchant, utility, or state-sponsored program, and may include Energy Efficiency, Load Management, and Distributed Generation projects that are installed after June 16, 2006, and that result in additional and verifiable reductions in end-use customer demand on the electricity network in the New England Control Area during specified ODR performance hours of the ICAP Transition Period.

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.

Out-of-Market Capacity is certain capacity that is counted in determining whether the Alternative Capacity Price Rule applies, as described in Section III.13.2.7.8 of Market Rule 1.

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, as remitting agent for the Covered Entities.

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.

Pivotal Supplier is defined in Section III.A.5.2.2 of Appendix A of Market Rule 1.

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.

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.E.7.

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 Load Zone or system-wide basis, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours. Beginning on June 1, 2011, "Real-Time Demand Resource Dispatch Hours" shall be defined as 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 Critical Peak Demand Resources and 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 the hours, or portions thereof, when the ISO dispatches Real-Time Demand Response Resources in the Load Zone where a Demand Resource is located in response to Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours. Beginning on June 1, 2011, Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Demand Resource Forecast Peak Hours and 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 the output of one or more emergency generators 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 to curtail electric consumption. Real-Time Emergency Generation Resources would be dispatched by the ISO on a 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. Beginning on June 1, 2011, 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 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, 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 Accepted Electric Industry 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.

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.

Re-Offer Period is the period normally between 16:00 and 18:00 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.

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.

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.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer, a DRP-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 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.

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.

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.

SPD means the ISO's Scheduling, Pricing, and Dispatch software, as more fully described in Section III.A.5.5.3 of Appendix A of Market Rule 1.

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.

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.

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.

Submitted Offer is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

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 Margin is defined in Section III.A.5.2.2 of Appendix A 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 Restoration and Planning Service is the form of Ancillary Service described in Schedule 16 of the OATT. System Restoration and Planning Service is referred to as blackstart service.

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 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 Load Zone or, starting on June 1, 2011, 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 Load Zone or, starting on June 1, 2011, 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.

UCS is Unit Commitment Software as more fully defined in Section III.A.5.5.3 of Appendix A of Market Rule 1.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

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

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

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

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

III.8 Demand Response Baselines

A Demand Response Baseline is calculated in 5-minute intervals for each Demand Response Asset for the following day types:

(a) weekdays (Monday-Friday) that are non-ISO settlement holidays;
(b) Saturdays, and;
(c) Sundays.

8.1 Demand Response Baseline Calculations

If a Demand Response Asset's metered demand represents a net supply of energy to the electrical system, the Demand Response Asset's metered demand in the interval will be set equal to zero and that zero demand value will be used in the Demand Response Baseline calculations for that interval pursuant to Sections III.8.2 and III.8.4.

8.2 Establishing an Initial Demand Response Baseline

The Demand Response Baseline for a Demand Response Asset with no previously computed Demand Response Baseline shall be the simple average of metered demand data for the asset for each five-minute interval, subject to the conditions in Section III.8.1, from the initial ten days of the same day type. The initial 10 days of meter data used to establish the Demand Response Baseline shall consist of the first 10 consecutive days of the same day type with a complete set of interval meter data. A Market Participant may not submit Demand Reduction Offers for a given day type until the month following the initial establishment of the Demand Response Baseline of the same day type for a Demand Response Asset.

8.3 Establishing a Demand Response Baseline for the Present Day

If, for a Demand Response Asset that has established an initial Demand Response Baseline, the Demand Reduction Offer of the Demand Response Resource associated with the Demand Response Asset is eligible in the Operating Day for payments pursuant to Section III.E.9, then the Demand Response Baseline of the Demand Response Asset, in each five-minute interval, for the present day is equal to the Demand Response Baseline of that Demand Response Asset, in the same five-minute interval from the prior day of the same day type.

8.4 Establishing a Demand Response Baseline for the Next Day of the Same Day Type

If, for a Demand Response Asset that has established an initial Demand Response Baseline:

(a) the Demand Reduction Offer of the Demand Response Resource associated with the Demand Response Asset is not eligible in the Operating Day for payments pursuant to Section III.E.9, or;
(b) the Demand Reduction Offer associated with the asset is eligible in the Operating Day for payments pursuant to Section III.E.9 and more than seven of the prior 10 days of the same day type have a Demand Response Baseline determined pursuant to Section III.8.3, then:

the Demand Response Baseline of the Demand Response Asset in each five-minute interval, for the next day of the same day type, is calculated as the sum of 0.9 times the Demand Response Baseline of that Demand Response Asset in the same five-minute interval from the prior day of the same day type and 0.1 times the Demand Response Asset's meter data, subject to the conditions in Section III.8.1, in the same five-minute interval in the present day.

8.5 Baseline Adjustment

For each day that a Demand Response Resource associated with a Demand Response Asset is scheduled in the Day-Ahead Energy Market or is dispatched in Real-Time for a demand reduction amount greater than zero, the ISO will calculate an adjustment factor equal to the average difference (MW) between the Demand Response Asset's metered demand and its Demand Response Baseline in the intervals during the two-hour period beginning two hours plus the Demand Response Resource's Start-up Time prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the Demand Response Asset's Maximum Load value. For purposes of establishing the adjusted Demand Response Baseline, if a Demand Response Asset's metered demand represents a net supply of energy to the electrical grid, the Demand Response Asset's metered demand in the interval will be set equal to zero.

SECTION III

MARKET RULE 1

APPENDIX E

DEMAND RESPONSE

APPENDIX E

DEMAND RESPONSE

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APPENDIX E
DEMAND RESPONSE

1. Demand Response Registration

1.1 Demand Response Resource Registration

A Market Participant may register a Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis for non-ISO settlement holidays subject to the following conditions:

(a) each Demand Response Resource must be a single Demand Response Asset or an aggregation of Demand Response Assets located within the same Dispatch Zone;
(b) each Demand Response Resource must be able to produce at least 100 kW of demand reduction, and;
(c) the Market Participant must comply with ISO required auditing and testing requirements.

A Market Participant may not register a Real-Time Emergency Generation Resource, an On-Peak Demand Resource, a Seasonal Peak Demand Resource or a Dispatchable Asset Related Demand to participate as a Demand Response Resource in the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant may not register an existing Generator Asset as a Demand Response Asset for the purpose of submitting Demand Reduction Offers.

1.2 Demand Response Asset Registration

A Market Participant may register a Demand Response Asset subject to the following conditions:

(a) Unless it meets the conditions for aggregation in sub-section (b) below, a Demand Response Asset must have a defined, single retail delivery point and be registered at a single Node.

(b) A Demand Response Asset may be the aggregate consumption of multiple end-use customers from multiple delivery points within a single Dispatch Zone if (i) the demand reduction from each retail delivery point in the aggregation is less than 10 kW, and (ii) the demand at the multiple retail delivery points satisfy the criteria for a homogenous population. A Demand Response

Asset that meets these conditions for aggregation must be registered at the Dispatch Zone rather than the Node.

(c) No more than one Demand Response Asset may be located at a single retail delivery point.

(d) Each Demand Response Asset must be mapped to a Demand Response Resource.

(e) Each Demand Response Asset must be able to produce at least 10 kW of demand reduction.

(f) A Demand Response Asset with the ability to offer a demand reduction equal to or greater than 5 MW from the same retail delivery point must be registered as a single Demand Response Resource at a Node.

(g) The metering and communication equipment associated with each Demand Response Asset must meet the requirements in Section III.E.2.

During the registration process, Market Participants must submit the following for each Demand Response Asset:

(a) Maximum Interruptible Capacity;

(b) Maximum Load;

(c) Maximum Generation, for Demand Response Resources that are comprised of Distributed Generation, and;

(d) retail account number and meter number for the end use customer.

1.3 Restrictions on Demand Response Resource Registration

A Market Participant may not register and must retire if previously registered a Demand Response Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

2. Metering and Communication

2.1 Interval Metering and Telemetry Requirements

The metered demand of each individual end-use customer facility that comprises a Demand Response Asset must be measured using interval meters located at the individual end-use customer's retail delivery point and shall be reported to the ISO at an interval of five minutes. Metered demand data submitted to the ISO shall not include average avoided peak distribution losses. Each generator located behind an individual end-use customer's retail delivery point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.

The interval meters required pursuant to Section III.E.2.1 must meet the following requirements:

(a) The interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes or less;

(b) If the interval meter is the same meter used by the distribution company for billing purposes, the meter is a revenue-quality meter that is accurate within ± 0.5%; and

(c) If the interval meter is not the same meter used by the distribution company for billing purposes, the interval meter is either a revenue-quality meter that is accurate within ± 0.5% or a non-revenue-quality meter with an overall accuracy of ± 2.0%. For each non-revenue-quality meter used, the Market Participant must, during the registration process, submit certification from the meter manufacturer that the interval meter being used meets the ± 2.0% accuracy threshold, and shall specify accuracy for the following parameters:

i. current measurement;
ii. voltage measurement;
iii. A/D conversion; and
iv. calibration.

2.2 Communication/Telemetry

The Market Participant must utilize a remote terminal unit for communicating telemetry and receiving dispatch instructions from the ISO.

Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facilities that comprise the Demand Response Asset on the electricity network in the New England Control Area.

For Demand Response Assets whose demand reductions are not achieved by Distributed Generation but where there is a generator located behind the retail delivery point, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility that comprises the Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of all generation.

For Demand Response Assets whose demand reductions are achieved by Distributed Generation, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility that comprises the Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of Distributed Generation associated with the Demand Response Asset.

2.3 Meter Testing

All interval meters must be periodically tested and calibrated.

Market Participants must conduct periodic meter data validation checks.

Market Participants must repair or replace meters that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters and meter data communication systems.

2.4 Auditing

The ISO may, for Demand Response Resources, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and measurement equipment, and witness the demand reduction activities of any facility associated with a Demand Response Asset.

Market Participants must make retail billing meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing and certifying the metering, data recording and measurement equipment of Demand Response Assets.

3. Day-Ahead Energy Market Demand Reduction Offers

Market Participants must submit a Demand Reduction Offer for each Demand Response Resource that meets the requirements of this section in order to be eligible for a demand reduction payment.

The Market Participant's Demand Reduction Offer for a Demand Response Resource must satisfy the following conditions:

(a) Demand Reduction Offers must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the applicable Operating Day.

(b) The Market Participant can submit up to 10 monotonically increasing price/demand reduction amount pairs for each Operating Day. The demand reduction amount shall not include an adjustment for average avoided peak transmission and distribution losses.

(c) The minimum amount for each price/demand reduction amount pair of a Demand Reduction Offer is 100 kW.

(d) The sum of all price/demand reduction amount pairs for a Demand Reduction Offer cannot exceed the sum of the Maximum Interruptible Capacities of the resource's Demand Response Assets.

(e) The minimum Demand Reduction Offer price must be equal to or greater than the Demand Reduction Threshold Price in effect for the day the Demand Reduction Offer is submitted.

(f) The maximum Demand Reduction Offer price must be less than or equal to $1000/MWh.

Market Participants may not Self-Schedule interruptions in the Day-Ahead Energy Market.

3.1 Required Demand Reduction Offer Parameters

The Market Participant shall provide the following hourly values in its Demand Reduction Offer. The Market Participant shall maintain up-to-date values for each of these parameters prior to and throughout the Operating Day:

(a) Available or Unavailable;

(b) Minimum Reduction (MW), and;

(c) Maximum Reduction (MW).

3.2 Optional Demand Reduction Offer Parameters

The Market Participant may also specify the following in its Demand Reduction Offer:

(a) Interruption Cost ($)

(b) Minimum Reduction Time (Hrs)

(c) Minimum Time Between Reductions (Hrs)

(d) Demand Response Resource Startup Time (Hrs)

(e) Demand Response Resource Notification Time (Hrs)

(f) Demand Response Resource Ramp Rate (MW/min)

4. Real-Time Energy Market Demand Reduction Offers

During the re-offer period, Market Participants may submit revisions to the price or demand reduction amount parameters of a Demand Reduction Offer. Demand Response Resources scheduled subsequent to the closing of the re-offer period shall be settled at the applicable Real-Time Prices.

Revisions to Demand Reduction Offers during the re-offer period are subject to the following conditions that apply to Day-Ahead Demand Reduction Offers under Section III.E.3: limitation to 10 monotonically increasing price/demand reduction amount pairs, minimum amount, maximum amount, minimum price and maximum price.

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for that Operating Day pursuant to Section III.E.5 or modified during the re-offer period.

No changes will be allowed to the Demand Reduction Offer after the close of the re-offer period. Market Participants may not Self-Schedule interruptions in the Real-Time Energy Market.

5. Scheduling and Dispatching

The ISO shall schedule in the Day-Ahead Energy Market and commit and dispatch in the Real-Time Energy Market the Demand Response Resource based on:

(a) least-cost, security-constrained dispatch and commitment as specified in Section III.1.7.6(a); and

(b) the Demand Reduction Offer for the Demand Response Resource, with demand reduction amounts adjusted by average avoided peak distribution losses.

At the conclusion of the Day-Ahead Energy Market clearing, the ISO will provide Market Participants with Day-Ahead demand reduction schedules for Demand Response Resources reflecting demand reduction amounts that do not include average avoided peak transmission and distribution losses for each hour of the following Operating Day.

During the Operating Day, the ISO will issue Dispatch Instructions to the Market Participant specifying the expected demand reduction amount that does not include average avoided peak transmission and distribution losses from their Demand Response Resource and the Dispatch Rate.

A Market Participant must notify the ISO, as soon as practicable, of a facility shutdown or equipment outage (including partial outages) that reduces the Demand Response Resource's ability to achieve the demand reduction reflected in the Demand Reduction Offer for an Operating Day.

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data for the same month of the previous year. The ISO may adjust the offer data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

(a) Each generator and import offer block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer block.

(c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

(d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from demand response exceeds the cost to load associated with compensating demand response.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} \times \frac{FPI_c}{FPI_h}$$

where FPI_h is the Forward Reserve Fuel Index for the same month of the previous year, and FPI_c is the Forward Reserve Fuel Index for the current month.

The ISO will post the resulting Demand Reduction Threshold Price on its website in advance of the Demand Reduction Threshold Price's effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Demand Response Resources located anywhere within the New England Control Area.

7. Real-Time Demand Reduction Obligation

A Demand Response Resource's Real-Time Demand Reduction Obligation will be calculated for each dispatch interval in which the Demand Response Resource receives a Dispatch Instruction to reduce demand.

7.1 Real-Time Demand Reductions

The Real-Time demand reduction in a dispatch interval is the difference between the adjusted Demand Response Baseline and the metered demand for each Demand Response Asset associated with the Demand Response Resource.

If a Market Participant receives a Dispatch Instruction for a Demand Response Resource to reduce demand in a dispatch interval by zero MW, then in calculating the Real-Time Demand Reduction

Obligation of the Demand Response Resource the Real-Time demand reductions of the Demand Response Assets comprising the resource shall be equal to zero for that dispatch interval.

7.2 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Demand Response Resource is the sum of the hourly integrated Real-Time demand reduction amounts of the Demand Response Assets comprising the Demand Response Resource, multiplied by one plus the percent average avoided peak distribution losses. In calculating the Real-Time Demand Reduction Obligation of a Demand Response Resource, the Real-Time demand reduction amounts of the Demand Response Assets comprising the resource shall be adjusted for net supply as specified in Section III.E.7.3 below.

If a Market Participant fails to comply with the metering and communication requirements in Section III.E.2 for a Demand Response Resource for any period of time, then the Real-Time Demand Reduction Obligation shall be zero for that period of time.

7.3 Treatment of Net Supply

If a Demand Response Asset's metered demand represents a net supply of energy to the electrical grid, the Demand Response Asset's metered demand in the interval will be set equal to zero and that value will be used in establishing the Real-Time Demand Reduction Obligation.

To the extent a Real-Time Emergency Generation Asset is located behind the retail delivery point of an individual end-use customer facility that comprises a Demand Response Asset and the Real-Time Emergency Generation Resource associated with the Real-Time Emergency Generation Asset is dispatched or audited pursuant to Section III.13, the metered output of the Real-Time Emergency Generation Asset, in each five-minute interval, shall be added to the metered demand measured at the retail delivery point in the same intervals for purposes of determining:

(a) a Demand Response Asset's Demand Response Baseline, and;

(b) the Real-Time demand reduction achieved by the individual end-use customer facility that comprises the Demand Response Asset.

8. Demand Response Resource Baseline

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8 prior to submitting a Demand Reduction Offer for a Demand Response Resource.

A Market Participant shall not take actions to create or maintain a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers in the absence of demand reduction payments.

9. Energy Market Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Demand Response Resource will be paid for its Day-Ahead Demand Reduction Obligation multiplied by the Day-Ahead LMP for the Dispatch Zone or Node at which the resource is registered.

9.2 Real-Time Settlement

A Market Participant with a Demand Response Resource will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the hourly Real-Time LMP for the Dispatch Zone or Node at which the resource is registered.

9.3 Cost Allocation

Charges or payments resulting from Real-Time demand reductions produced by Demand Response Resources or Real-Time Emergency Generation Resources shall be allocated on an hourly basis proportionally to Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

9.4 NCPC Credits and Charges

A Market Participant with a Demand Response Resource is eligible for NCPC credits if the resource is following Dispatch Instructions. A Market Participant with a Demand Response Resource is ineligible for NCPC credits and may be assessed NCPC charges if the resource is not operating within the acceptable dispatch tolerance. A resource is not operating within the acceptable dispatch tolerance if in any five-minute interval for an hour the resource is not operating within 10% above or below the resource's Dispatch Instruction, except that a Market Participant with a resource that is not operating within the acceptable dispatch tolerance will not be assessed NCPC charges if during the entire hour the resource operates within 5% above or below the resource's Dispatch Instruction.

10. Average Avoided Peak Distribution Losses

For purposes of Section III.E, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

Attachment 5

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. **)** **Docket No. ER11-___-000**

TESTIMONY OF HENRY Y. YOSHIMURA

I. WITNESS IDENTIFICATION.

Q: Please state your name, title, and business address.

A: My name is Henry Y. Yoshimura. I am the Director of Demand Resource Strategy for ISO New England Inc., One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: Please summarize your job responsibilities at ISO New England Inc.

A: I joined ISO New England Inc. (the "ISO") in 2002. In my current position, I am responsible for the development of demand resource initiatives for the New England wholesale electricity market and assist ISO business units implement these initiatives.[1] I manage the ISO's Demand Resources Department to develop program and market designs that integrate demand resources into the wholesale electricity markets, work with the ISO's Market Design group under the direction of Dr. Robert Ethier, the Vice President of Market Development, and work with external and internal stakeholder groups (*e.g.*, program participants, demand resource providers, New England Power Pool ("NEPOOL") Participants, state and Federal regulators, and the ISO's Market and System Operations, Planning,

[1] Capitalized terms used but not defined in this testimony are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 ("ISO Tariff"), the Second Restated New England Power Pool Agreement, and the Participants Agreement.

Settlements and IT Departments) to successfully implement such programs and market designs. I also help integrate the ISO's demand resource initiatives with other markets such as the capacity, reserve and regulation markets, and with the ISO's Regional System Planning process in order to ensure efficient market design and consistent planning assumptions. I have appeared before the Federal Energy Regulatory Commission ("Commission") on several occasions addressing demand response in organized electricity markets. Specifically, I appeared before the Commission in technical conferences on Demand Response in Organized Electric Markets held on April 23, 2007 in Docket No. AD07-11-000 and May 21, 2008 in Docket No. AD08-8-000, and concerning the National Action Plan on Demand Response held on November 19-20, 2009 in Docket No. AD09-10-000.

Q: Please summarize your experience and qualifications prior to joining the ISO.

A: Before joining the ISO, I spent approximately two years in Jakarta, Indonesia with the Institute of International Education as the Chief of Party of a USAID-sponsored project in which I led and mentored a group of Indonesian staff to advise and assist the Government of Indonesia to restructure the Indonesian electricity sector and set up appropriate regulatory institutions. Before my assignment in Indonesia in 2000, I was a Senior Consultant of Economics and Public Policy for XENERGY Consulting, Inc., where I managed a variety of projects related to electric industry restructuring in the United States. Before joining XENERGY in 1997, I was a Senior Consultant with La Capra Associates, a Boston-based consulting firm specializing in utility regulatory matters. While with La Capra, I assisted several electric and gas utilities evaluate the cost-effectiveness of demand-side management options for inclusion in their integrated resource plans. I also advised the Massachusetts Division of Energy Resources ("DOER") in a series of proceedings including the Massachusetts Department of Public Utilities ("DPU") rulemaking concerning electric industry restructuring and assisted the DOER in settlement negotiations with Massachusetts Electric Company ("MECo") concerning the structure of MECo's restructuring plan, including the structure of the Standard Offer bidding process. Before joining La Capra Associates in 1992, I served on the staff of the DPU for about ten years and held several positions including Senior Economist, Assistant Director of the Electric Power Division, and Director of the Electric Power Division. As Director of the DPU's Electric Power Division, I managed staff working in the areas of utility cost of service and rate design, integrated resource planning, and demand-side management. I participated in the development and implementation of numerous regulatory policies such as marginal cost-based rate design, cost recovery standards for utility generation, competitive bidding regulations for non-utility generation, integrated resource management, and the incorporation of environmental externalities in utility integrated resource planning.

I have bachelor and graduate degrees in economics from the University of Montana. Including my work in graduate school, which was in the energy field, I have about 29 years of domestic and international experience as an economist and public policy expert in the electric power industry.

II. BACKGROUND, PURPOSE, SCOPE OF DIRECT TESTIMONY.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to explain the proposed rules and supporting studies submitted by the ISO in compliance with the order issued by the Commission on March 15, 2011 concerning demand response compensation in organized wholesale energy markets.[2] My testimony will explain each major element of the ISO's compliance filing.

Q: What is the Commission's "Final Rule" with respect to demand response compensation in organized wholesale energy markets?

A: The final rule, codified as 18 CFR § 35.28(g)(1)(v), states:

> Each Commission-approved independent system operator or regional transmission organization that has a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals must:
>
> (A) pay to those demand response resources the market price for energy for these reductions when these demand response resources have the capability to balance supply and demand and when payment of the market price for energy to these resources is cost-effective as determined by a net benefits test accepted by the Commission; and
>
> (B) allocate the costs associated with demand response compensation proportionally to all entities that purchase

[2] *Demand Response Compensation in Organized Wholesale Energy Markets*, Final Rule, 134 FERC ¶ 61,187, Order No. 745, Docket No. RM10-17-000, March 15, 2011 ("Order No. 745").

from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched.[3]

Q: What is the ISO required to file with the Commission pursuant to Order No. 745?

A: Order No. 745 requires each Regional Transmission Organization and Independent System Operator with a tariff provision permitting demand resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals to submit a compliance filing that includes the following elements:

1. **Tariff changes implementing:**

- **The required demand response compensation approach,** which pays demand response providers the full locational marginal price ("LMP") for reductions in electric energy consumption relative to expected levels in response to price signals, to the extent that:

  (a) A demand resource is able to displace generation resources in a manner that serves the RTO or ISO in balancing supply and demand, and

  (b) The provision of that service is cost-effective as determined by the Commission's consumer net benefits test;[4]

- **A monthly determination of the price level at which the dispatch of demand resources is cost-effective** in that the reduction in total consumer energy payments from reduced LMPs produced by demand resources is greater than the cost of paying LMPs to those demand response providers,[5]

[3] Order No. 745 at P 97.

[4] Order No. 745 at PP 47, 48.

[5] Order No. 745 at PP 4, 78.

subject to "changes needed to ensure that measurement and verification of demand response will adequately capture the performance (or non-performance) of each participating demand response market participant;"[6]

- **The required demand response cost allocation mechanism,** where the costs associated with payments to demand response providers are allocated proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time demand resources are committed or dispatched;[7] and

- **Changes to the estimation of customer baselines,** if necessary, to ensure that demand response baselines remain accurate so that reductions in a resource's energy consumption can be measured and verified.[8]

2. **A description of the methodology, the analysis, associated data and the actual supply curves** used to determine the monthly threshold prices for the last 12 months, which will be used to implement the Commission's consumer net-benefits test.[9]

3. **An explanation of how the ISO's measurement and verification protocols** will continue to ensure that appropriate baselines are set, and that demand response will continue to be adequately measured and verified to ensure performance of each resource.[10]

[6] Order No. 745 at P 94.

[7] Order No. 745 at P 102.

[8] Order No. 745 at P 94.

[9] Order No. 745 at PP 79, 80.

[10] Order No. 745 at P 94.

Q: How is the remainder of the testimony organized?

A: The remainder of the testimony will explain the market rules proposed by the ISO to comply with Order No. 745. The ISO proposes two sets of market rules, which include:

1. An approach that fully integrates demand resources into the ISO's day-ahead and real-time energy markets, which the ISO plans to implement on June 1, 2015.

2. An approach that modifies the ISO's current price-response programs, which the ISO plans to implement on June 1, 2012 and keep in place until the fully integrated approach is implemented.

Attached to this testimony are three exhibits that meet the Commission's filing requirements and support various elements of the ISO's proposed market rules. These exhibits include:

- ***EXHIBIT A*** consisting of a report entitled "Development of Demand Response Price Thresholds" prepared by Charles River Associates on behalf of the ISO, which validated the supply curve approach outlined in Order No. 745 by comparing its results to that of a more sophisticated analysis using an hourly, security-constrained dispatch model.

- ***EXHIBIT B*** showing the results of the ISO's proposed methodology for estimating monthly Demand Reduction Threshold Prices, which implements the Commission's consumer net benefits test. This exhibit also includes the data used and the estimated supply curves for the 12-month period from January through December 2010.

- ***EXHIBIT C*** consisting of a report entitled "Analysis and Assessment of Baseline Accuracy" prepared by KEMA on behalf of the ISO, which reviewed the ISO's current measurement and verification requirements and recommended revisions to improve accuracy and decrease bias of the ISO's baseline estimation methodology.

I will explain each exhibit at the appropriate juncture later in this testimony.

III. PROPOSED RULES

A. SUMMARY OF THE ISO'S COMPLIANCE APPROACH

Q: What is the best overall approach to complying with Order No. 745, and why?

A: The best overall approach to complying with Order No. 745 is to fully integrate demand resources into the day-ahead and real-time energy markets and system operations infrastructure.

The Commission requires that demand resources able to displace generation resources in a manner that helps to balance supply and demand should be paid the full LMP to the extent the provision of that service is cost-effective as determined by the Commission's consumer "net benefits test."[11] To effectively commit and dispatch demand resources as an alternative to committing and dispatching generation resources in balancing energy supply and demand, supply offers from demand resources should be considered at the same time as supply offers from generation resources. Full integration would allow for such side-by-side comparisons of resources and would better ensure that the most cost-effective resources available at each moment in time are committed and dispatched to serve regional energy consumption.

Furthermore, full integration of demand resources into market and system operations infrastructure would improve the operational flexibility and reliability of the electric system. By allowing demand response providers to express a price at which they are willing and able to reduce demand, demand resources become available to assist in balancing supply and demand in the energy market apart from capacity deficiency and system emergency conditions. Access to demand resources *before* capacity deficiency and system emergency conditions arise

[11] Order No. 745 at P 48.

would reduce the use of capacity deficiency and emergency operating procedures and improve system reliability.

Q: What could happen if the ISO did not fully integrate demand resources into the day-ahead and real-time energy markets?

A: Lacking full integration, LMPs in the day-ahead energy market could be established before demand resources are scheduled, which would result in demand resources having only an indirect impact on day-ahead LMPs.[12] Also, by not planning and accounting for demand reductions produced by demand resources, the ISO may over-commit generation resources given that less generation may be needed in real time if actual system demand is significantly reduced by demand resources. Over-committing resources can result in higher-than-necessary supply costs. Also, inability to dispatch demand resources at a price specified by demand response providers before shortage conditions occur could result in a less reliable system and an increase in the use of capacity deficiency and emergency operating procedures.

Q: Please describe the overall market design approach the ISO is proposing with respect to the full integration of demand resources into the day-ahead and real-time energy markets.

A: The ISO's market design approach with respect to the full integration of demand resources into the energy markets is to treat a Demand Reduction Offer from a demand resource in the same manner as a Supply Offer from a generator. Based upon all of the offers submitted for both generation and demand resources, the optimal set of resources that minimizes production costs subject to reliability constraints would be committed and dispatched. Energy resources that were cleared in the Day-Ahead Energy Market would be paid the Day-Ahead LMP.

[12] Although demand response may not directly affect Day-Ahead LMPs if scheduled after the close of the Day-Ahead Energy Market, it will have an indirect effect over time. That is, prices and bids in Day-Ahead Energy Markets should begin to reflect altered bidding strategies of Market Participants in response to and in anticipation of demand response, which will affect Day-Ahead LMPs.

Deviations between cleared Day-Ahead Energy Market positions and actual resource performance in real time would be settled at the Real-Time LMP.

In order to balance supply and demand in real time, Dispatch Instructions to energy resources could vary from the schedule of resource commitments produced by the clearing of the Day-Ahead Energy Market, or from the schedule of supplemental resource commitments coming out of the reserve adequacy analyses conducted by the ISO just prior to and during the Operating Day. This is because conditions in real time will vary from forecasted conditions upon which resource commitments were made. Because the energy market offers for both generation and demand resources are allowed to express certain inter-temporal parameters,[13] Dispatch Instructions to a resource that vary from a resource's commitment could result in the resource incurring costs that are not recovered through LMP-based energy payments. In these circumstances, demand response providers will receive make-whole payments known as Net Commitment Period Compensation or "NCPC." Market participants with resources that do not perform in real time in accordance with Dispatch Instructions would not be eligible to receive NCPC payments, and may receive an allocation of NCPC charges.

Q: At what point in time does the ISO propose to implement the solution that fully integrates demand resources into the day-ahead and real-time energy markets?

A: The ISO proposes to implement the fully integrated solution on June 1, 2015. The ISO initially proposed that the fully integrated solution be implemented on June 1, 2014. However, several demand response providers indicated that their participation in the June 2011 Forward Capacity Auction, which would determine Capacity Supply Obligations for the 2014/2015 Capacity Commitment Period,

[13] Examples of inter-temporal parameters include Interruption Cost ($), Minimum Reduction Time (Hrs), demand resource Startup Time (Hrs).

could be adversely affected given uncertainty in the market rules concerning energy market participation of demand resources with Capacity Supply Obligations in that year. The ISO was not in a position to file market rules with the Commission with respect to the fully integrated solution before the completion of the June 2011 Forward Capacity Auction. Accordingly, the ISO decided to forestall the proposed implementation of the fully integrated solution until June 1, 2015 – *i.e.*, the beginning of the 2015/2016 Capacity Commitment Period.

Q: Will there be any price-responsive demand program in New England before June 1, 2015?

A: Yes. Since the ISO has committed to delay implementation of the fully integrated solution until June 1, 2015, a transitional solution that complies with the Order No. 745 and that can be implemented expeditiously and inexpensively will provide an opportunity for the New England region to continue to achieve benefits from price-responsive demand until the fully integrated solution becomes effective. By the terms of the currently-effective tariff rules, the ISO's existing price-responsive demand programs are only effective through May 31, 2012. Accordingly, the ISO proposes to put in place a new, transitional solution that builds upon the expiring price-response program infrastructure,[14] but includes changes that comply with Order No. 745. The current plan is to implement the new, transitional solution on June 1, 2012, and to replace the transitional solution with the fully integrated solution on June 1, 2015.

[14] The transitional solution will be based on the present Day-Ahead Load Response Program, which is a bid-based program in which a Market Participant with a Real-Time Demand Response Asset can submit demand reduction offers concurrent with the Day-Ahead Energy Market consisting of a price, which must exceed a minimum threshold level, and a demand reduction amount, which must be greater than or equal to 100 kW. *See* Section III.E.2 of the ISO Tariff. The demand reduction offer may also include a curtailment initiation price, which enables the Market Participant to declare a fixed cost that must be recovered per interruption/start-up, and up to a four-hour minimum interruption duration period, which enables the Market Participant to state the minimum amount of time for which the energy consumption of the Real-Time Demand Response Asset must be interrupted if scheduled.

Q: How do these solutions – *i.e.*, the fully integrated solution and the transitional solution – comply with Order No. 745?

A: The ISO's proposed market rules for both the fully integrated and the transitional solutions comply with Order No. 745 because they:

1. Pay demand response providers the full LMP for reductions in electric energy consumption relative to expected levels in response to price signals, to the extent that the demand resource is able to displace a generation resource in a manner that facilitates the balancing of supply and demand, and that the provision of that service is cost-effective as determined by the Commission's consumer net benefits test.[15]

2. Require the ISO to determine on a monthly basis a Demand Reduction Threshold Price that defines the LMP level at or above which the reduction in total consumer energy payments from reduced LMPs produced by demand resources is greater than or equal to the cost of paying demand response providers.[16] The proposed market rules for both the fully integrated and transitional solutions comply with the Commission's consumer net benefits test by requiring that Demand Reduction Offers be made at or above the Demand Reduction Threshold Price.

3. Modify the method used by the ISO to estimate Demand Response Baselines to ensure that baselines remain accurate so that reductions in a demand resource's energy consumption can be measured and verified.[17] The proposed baseline estimation method uses the ISO's current methodology with modifications to better assure baseline accuracy should demand resources clear the energy markets frequently.

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[15] Order No. 745 at PP 47, 48.

[16] Order No. 745 at PP 4, 78, 94.

[17] Order No. 745 at P 94.

4. Require that charges or payments resulting from demand reductions produced by demand resources be allocated on an hourly basis proportionally to all entities that purchase from the relevant energy market in the areas where the demand response reduces the market price for energy at the time demand resources are committed or dispatched.[18]

[18] Order No. 745 at P 102.

B. RULES IMPLEMENTING THE FULLY INTEGRATED SOLUTION

1. OVERVIEW

Q: Please describe the scope of the ISO's proposed tariff provisions that fully integrate demand resources into the day-ahead and real-time energy markets.

A: The ISO's proposed tariff provisions that fully integrate demand resources in the day-ahead and real-time energy markets consist of ten sections of revised Appendix E to Market Rule 1. These sections include:

1. Demand Response Registration
2. Metering and Communication
3. Day-Ahead Energy Market Demand Reduction Offers
4. Real-Time Energy Market Demand Reduction Offers
5. Scheduling and Dispatching
6. Determination of the Demand Reduction Threshold Price
7. Real-Time Demand Reduction Obligation
8. Demand Response Baseline
9. Energy Market Settlement
10. Average Avoided Distribution Losses.[19]

2. DEMAND RESPONSE REGISTRATION

Q: Please describe the ISO's proposed tariff provisions regarding demand response registration.

A: The demand response registration section[20] describes the conditions under which a Market Participant may register a Demand Response Resource[21] for purposes of

[19] Conforming changes to Sections I.2.2 and III.8 of the ISO Tariff are included, as well.

[20] *See* proposed Appendix E for the fully integrated solution ("FIS Appendix E") at § 1.

[21] Note that "Demand Response Resource" and "Demand Response Asset" are new defined terms that become effective with the implementation of the fully integrated solution. A Demand Response Resource consists of one or more Demand Response Assets located within the same Dispatch Zone. The present (continued...)

submitting Demand Reduction Offers into the day-ahead and real-time energy markets. The most important provisions of this section are the provisions that describe the rules for the aggregation of the demand reduction capabilities of individual, end-use customers – *i.e.*, Demand Response Assets – into a single Demand Response Resource that participates in the wholesale energy markets.[22]

Allowing for the aggregation of individual, end-use customers into a resource portfolio helps demand response providers improve overall resource performance by managing volatility in the day-to-day and hour-by-hour availability of customers to respond to a Dispatch Instruction. For example, take two separate assets each with 10 MW of demand reduction capability offering to reduce demand at the same price. Say that in a particular hour, the ISO needed 10 MW of additional resources (*i.e.*, 10 MW of additional generation or demand reduction) to balance supply and demand in real time. If the price offered for each of the two assets were lower than the price offered for the next available resource, the ISO would send a Dispatch Instruction to each asset to reduce demand by 5 MW. If one asset happened not to be available to reduce demand while the other asset was available, the ISO would only receive 5 MW out of the 10 MW requested by dispatching each asset separately. On the other hand, by aggregating the two assets into a single resource, the demand response provider could meet the ISO's full 10 MW Dispatch Instruction by reducing the demand of the one asset that was fully available in that hour.

While aggregation of Demand Response Assets into Demand Response Resources is allowed by the proposed market rules, it is important to note that aggregation is not required. A Demand Response Resource could consist of a single Demand

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(...continued)
tariff uses the terms "Real-Time Demand Response Resource" and "Real-Time Demand Response Asset" to refer to active demand resources and assets that participate in the Forward Capacity Market and the Day-Ahead Load Response Program. The terms Real-Time Demand Response Resource and Real-Time Demand Response Asset will continue to be used in the transitional solution, but be retired when the fully integrated solution for the energy markets becomes effective.

[22] *See* FIS Appendix E at § 1.2(b).

Response Asset as long as that asset can meet the minimum offer size requirement.

3. AGGREGATION OF DEMAND RESPONSE ASSETS

Q: Are there rules governing the aggregation of Demand Response Assets into a Demand Response Resource?

A: Yes.[23] Each Demand Response Asset must have a defined, retail delivery point, and must be registered at a single Node. Demand Response Assets located at Nodes within the same Dispatch Zone may be aggregated into a Demand Response Resource. A Dispatch Zone is a subset of Nodes located within a Load Zone that reflect potential transmission constraints within the Load Zone that are expected to exist during each Capacity Commitment Period. Each Demand Response Asset must be able to produce at least 10 kW of demand reduction. Further, a Demand Response Asset with the ability to reduce demand in an amount equal to or greater than 5 MW at a single retail delivery point must be registered as a single Demand Response Resource at a Node.

Q: Why must a Demand Response Asset with the ability to offer a demand reduction equal to or greater than 5 MW at a single retail delivery point be registered as a single Demand Response Resource at a Node?

A: A Demand Response Asset with a large amount of interruptible demand at a single Node could cause reliability problems in areas with local transmission constraints if the ISO were not able to anticipate sudden changes in consumption at those Nodes. Since a demand response provider is allowed to exercise discretion over which assets in its portfolio it would use to comply with a Dispatch Instruction, allowing a large Demand Response Asset to be aggregated with other Demand Response Assets would reduce the ISO's ability to control the dispatch of the large asset, which may be located in an area with local

[23] *Id.*

transmission constraints. For reliability purposes, therefore, each large asset needs to be registered as a single Demand Response Resource at a Node.[24]

Q: If a Demand Response Asset must be able to produce at least 10 kW of demand reduction, how do customers with less than 10 kW of demand or customers able to provide only small demand reduction amounts participate in the wholesale energy markets as a Demand Response Asset?

A: The ISO's proposed market rules allow a Demand Response Asset to be made up of multiple end-use customers from multiple delivery points located within a single Dispatch Zone if the demand reduction from each retail delivery point in the aggregation is less than 10 kW, and the end-use customers making up such an aggregation are from a homogenous population (*e.g.*, residential customers, small commercial customers). A Demand Response Asset that meets these conditions for aggregation must be registered at a Dispatch Zone rather than at a Node.

4. METERING AND COMMUNICATION

Q: Please describe the ISO's proposed tariff provisions regarding metering and communication.

A: The ISO's proposed market rules require that the actual metered demand of each individual end-use customer facility that comprises a Demand Response Asset be measured using interval meters, capable of recording energy consumption at least every five minutes, located at the individual end-use customer's retail delivery point. These data must be reported to the ISO at an interval of five minutes.[25]

Five minute data are needed, given that the dispatch of energy resources and Real-Time LMPs are determined every five minutes. Also, these metering and communication requirements are consistent with the present metering

[24] *See* FIS Appendix E at § 1.2(f).

[25] *See* FIS Appendix E at § 2.1.

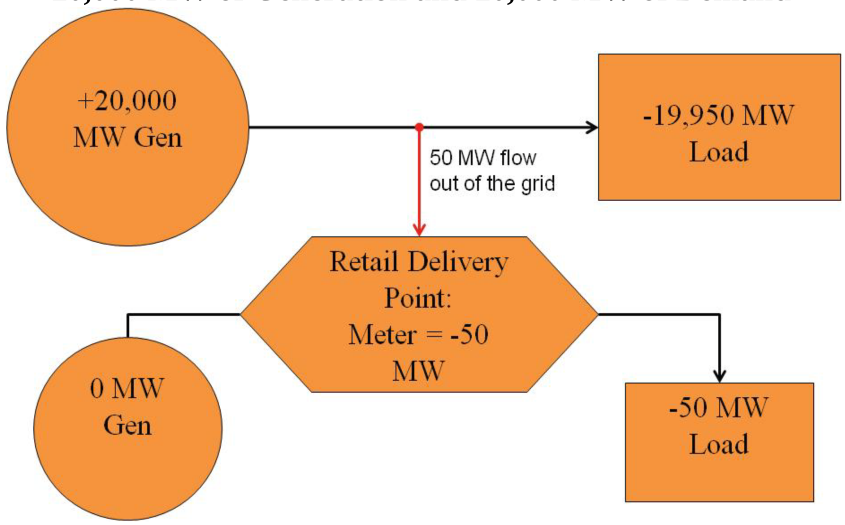
requirements for Real-Time Demand Response Assets currently participating in the Forward Capacity Market. By using the same metering and communication requirements, demand response participation in the wholesale energy markets can be facilitated using the same infrastructure previously developed by the ISO for demand response participation in the Forward Capacity Market.

Q: Why is measurement at the retail delivery point required?

A: There are four reasons for requiring measurement at the Demand Response Asset's retail delivery point. First and foremost, the demand served by the electricity network in the New England Control Area (*i.e.,* "the grid") is a function of the electrical demands at all points of interconnection between the grid and each consumer of electrical energy. The point of interconnection between the grid and a consumer of electrical energy is called the "retail delivery point." It is the electrical demand at each retail delivery point that defines the customer's demand served by the grid, which also defines the amount of demand response that each customer can provide to the grid to help balance supply and demand.

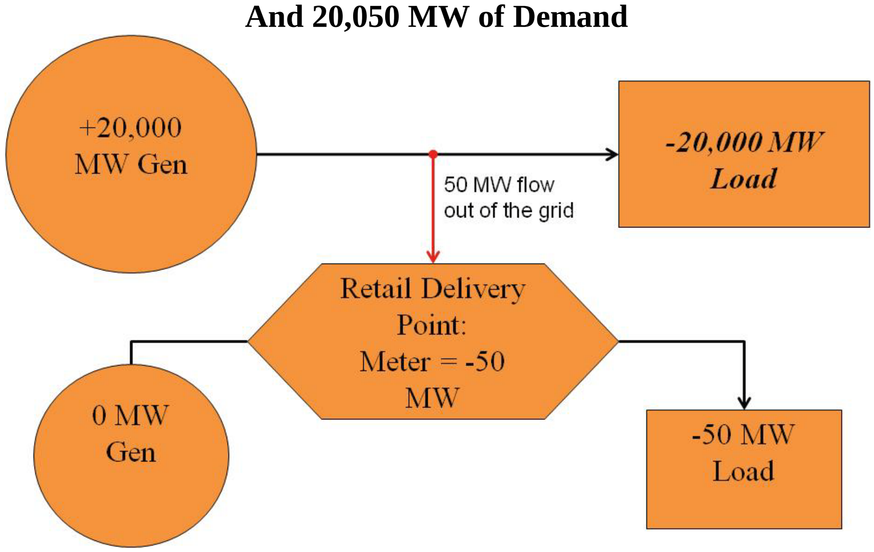
For example, a customer consuming 50 MW who does not produce its own energy places a 50 MW demand on the grid, which requires the ISO to dispatch generation to serve that customer's demand in addition to serving the demand of all other customers on the grid (***see Figure 1***).

Figure 1: BASE CASE A – Power System in Balance
20,000 MW of Generation and 20,000 MW of Demand



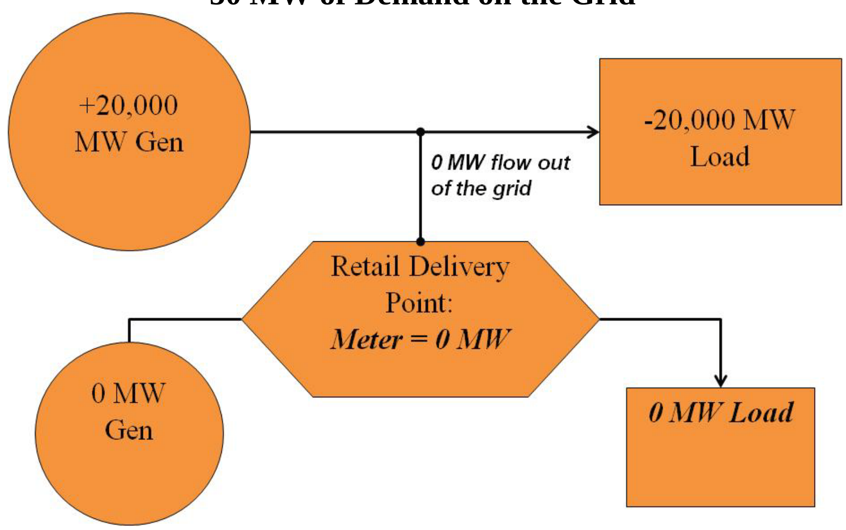
If the demand on the grid increases, all other things being equal, demand will exceed supply and the system will be out of balance (***see Figure 2***).

Figure 2: Power System Out of Balance – 20,000 MW of Generation
And 20,050 MW of Demand



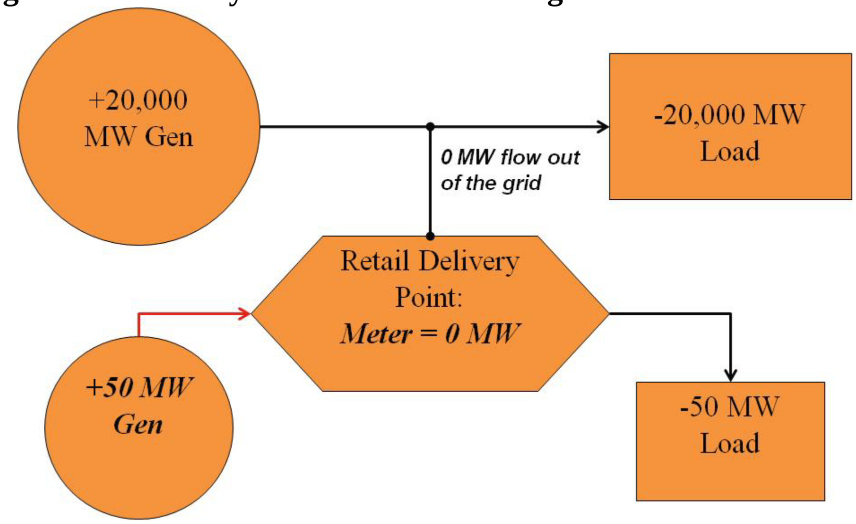
Assume that the 50 MW customer featured in these examples decides to participate in the wholesale energy market as a Demand Response Resource. The ISO would compare all of the Demand Reduction Offers and Supply Offers submitted to the ISO to determine which 50 MW resource ought to be dispatched to bring supply and demand back into balance at the lowest possible cost. ***Figure 3*** shows the impact of the customer's demand reduction on the electric system. By providing 50 MW of demand response to the grid, this customer helped to rebalance supply and demand in real time. To the extent payment for this demand response is cost-effective pursuant to the Commission's consumer net-benefits test, Order No. 745 requires that this customer be paid the full LMP for 50 MW of demand response it provided to the grid.

Figure 3: Power System Rebalanced By Reducing 50 MW of Demand on the Grid



Alternatively, a customer with distributed generation (*i.e.*, a generator located behind the retail delivery point, which can directly serve the customer's electrical demand) could reduce demand from the grid by dispatching 50 MW of generation behind the retail delivery point. ***Figure 4*** shows the impact of the dispatch of that distributed generation on the grid, which has an equivalent value in helping to rebalance supply and demand in real time as the customer's energy consumption reduction shown in ***Figure 3***.

Figure 4: Power System Rebalanced Using Distributed Generation

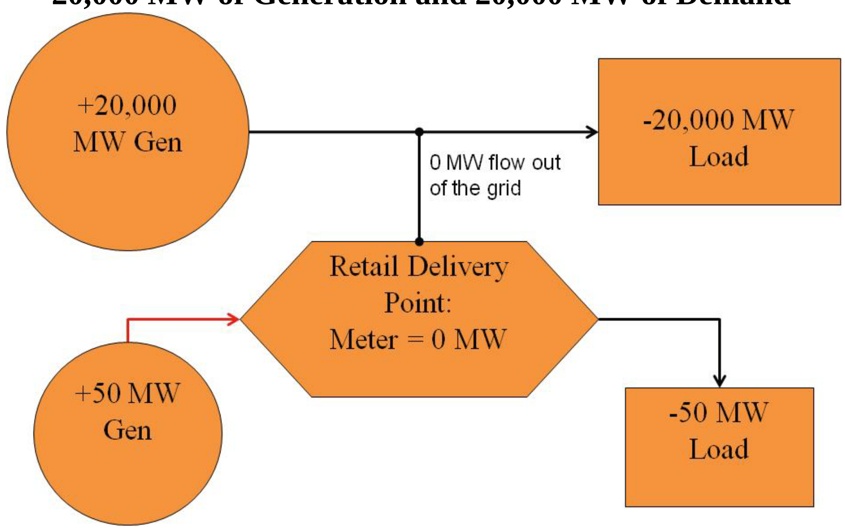


The impact of this demand resource on the grid was a change from 50 MW flowing out of the grid (***see Figure 2***) to 0 MW flowing out of the grid (***see Figures 3 or 4***). That is, this demand resource provided 50 MW of demand response to the grid. Two important observations arise from these examples: (1) the quantity of impact a demand resource has on the grid can only be measured at the resource's retail delivery point, and (2) the same 50 MW reduction in demand on the grid was produced regardless of whether the customer reduced energy consumption ***(Figure 3)*** or dispatched its distributed generator ***(Figure 4)***. To the extent payment for distributed generation-facilitated demand response is cost-effective pursuant to the Commission's consumer net-benefits test, Order No. 745 requires that this customer be paid the full LMP for the 50 MW of demand response it provided to the grid.

Q: The examples in *Figures 1* through *4* show that the distributed generator behind the retail delivery point was normally *off* and the customer's demand was served by the grid. Is the amount of demand response that a customer can deliver to the grid different if the distributed generator behind the retail delivery point was normally *on* and the customer's demand was not served by the grid?

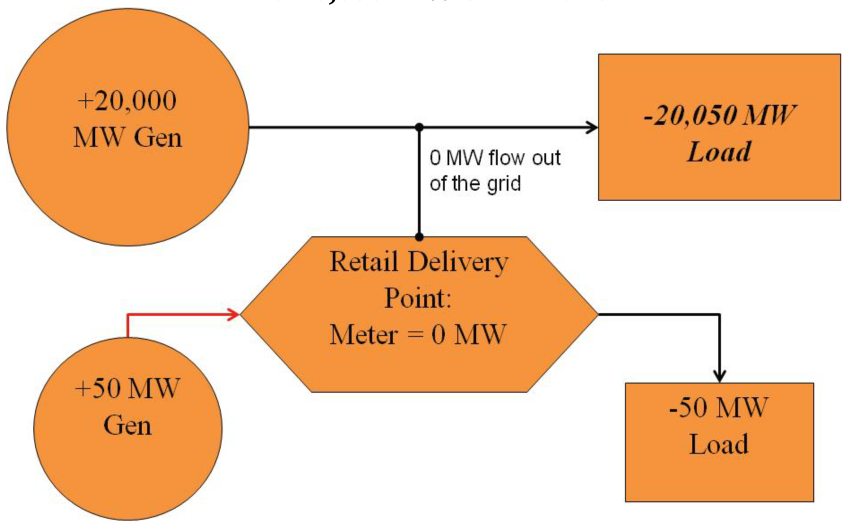
A: Yes. A customer who decides to serve its own electrical demand as opposed to placing its demand on the grid has a different impact on the grid to begin with – *i.e.*, the grid does not dispatch resources to serve the customer's demand. For example, a customer consuming 50 MW who also generates 50 MW behind the retail delivery point places no demand on the grid. Therefore, the meter at the retail delivery point reads 0 MW of consumption (***see Figure 5***).

Figure 5: BASE CASE B – Power System in Balance
20,000 MW of Generation and 20,000 MW of Demand



If demand on the grid grows by 50 MW all other things equal, demand will exceed supply and the system will be out of balance by 50 MW (***see Figure 6***).

Figure 6: Power System Out of Balance – 20,000 MW of Generation And 20,050 MW of Demand



Because the meter at the hypothetical customer's retail delivery point is 0 MW, the grid operator had dispatched no resources to serve the hypothetical customer's energy consumption. Therefore, reducing the demand of this customer does not result in generation elsewhere on the system being made available to serve increased system demand.

Rather, if the customer reduces 50 MW of energy consumption, all other things being equal, 50 MW will be injected into the grid (***see Figure 7a***).[26] Similarly, if the customer increases generator production to 100 MW (and does not reduce energy consumption), 50 MW will be injected into the grid (***see Figure 7b***). Whether the customer reduces demand, increases generation, or any combination thereof resulting in a 50 MW injection of energy into the electric system, the 50 MW should be compensated at the full LMP like a generator.

[26] These examples assume that the customer is appropriately permitted and interconnected to export energy to the wholesale power system.

Figure 7a: Power System Rebalanced Using Distributed Generation

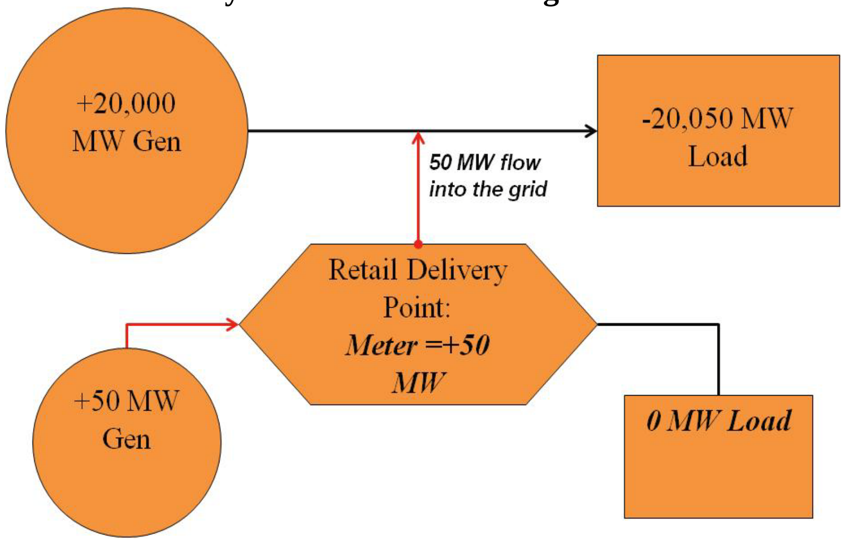
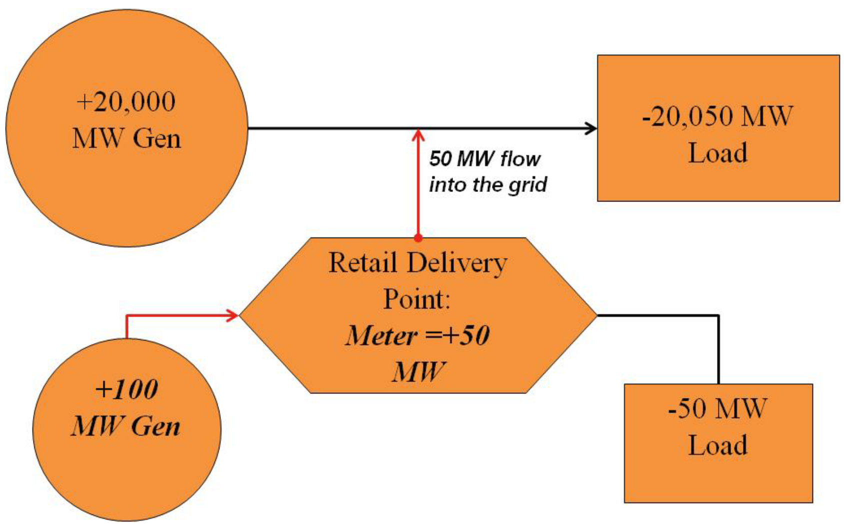


Figure 7b: Power System Rebalanced Using Distributed Generation



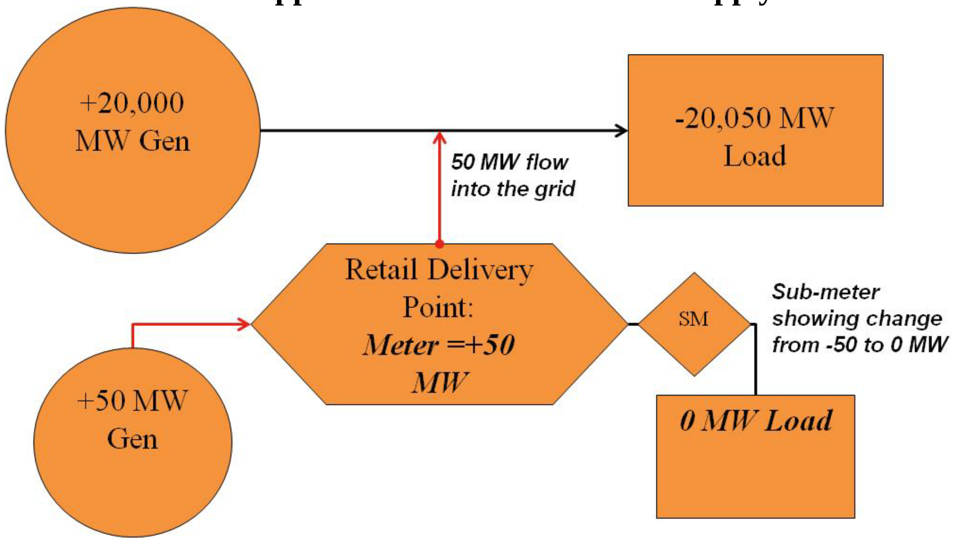
What ***Figures 5* through *7*** illustrate is that a customer who normally serves its own energy consumption with distributed generation cannot provide demand response to the grid given that the grid did not serve its demand in the first place. However, these figures also illustrate that a customer who normally serves its own energy consumption with distributed generation can provide value to the market by injecting energy into the electric system, which can be used to balance supply and demand like a generator. The amount of energy delivered to the grid, regardless of how that energy was produced, ought to receive compensation.

In all of the above examples, the amount of energy that a customer delivers to the grid (whether in the form of demand response or generation) to help balance supply and demand is a function of the customer's demand measured at the point of interconnection with the grid, *i.e.*, at the customer's retail delivery point.

Q: Earlier you stated that there were four reasons why measurement at the retail delivery point is required. What are the other three reasons?

A: Second, if demand response were measured at a point other than the retail delivery point, the danger of double-counting the amount used to balance supply and demand in real time is greatly enhanced. For example, if a sub-meter was placed on the demand behind the retail delivery point and was used to measure and compensate the customer for demand response, and the meter at the retail delivery point was separately used to measure and compensate the customer for generation flowing into the grid, a single 50 MW demand reduction could result in two payments – a 50 MW payment for generation that normally serves the customer's demand but is injected into the grid when demand is reduced, and a 50 MW payment for demand response, which created the injection of generation into the grid. The placement of meters in this way could result in a total payment of 100 MW multiplied by the LMP even though only 50 MW were produced and delivered to the grid to balance supply and demand in real time (***see Figure 8***). Consistent measurement of the impact on the grid of a customer's demand response or generation resource at the customer's retail delivery point would avoid potential double-counting of the amount delivered to the grid to balance supply and demand.

Figure 8: Strategic Sub-Meter Placement Could Result in Double-Counting the MW Supplied to the Grid to Balance Supply and Demand



Third, all retail delivery points have revenue-quality meters installed, operated, and maintained by the customer's utility distribution company. In many cases, the same meter could be used to measure the demand response (or generation) provided by a customer to the grid, thus minimizing costs.

Finally, because the meter at the retail delivery point is read by the utility distribution company for retail billing purposes**,** the meter data recorded by the utility can be used by the ISO to verify the meter data submitted by demand response providers to the ISO for settlement purposes. The proposed market rules require that Market Participants make available to the ISO, upon request, retail billing meter data from the Host Participant for the facilities associated with a Demand Response Asset.[27] Because demand response providers have a financial interest in submitting meter data that produce a larger financial settlement, verifying the accuracy of the meter data submitted by demand response providers is critical.

[27] *See* FIS Appendix E at § 2.4.

Q: Are there other important metering requirements in the ISO's proposed rules?

A: Yes. Each generator located behind an individual end-use customer's retail delivery point must be separately measured using an interval meter and must be reported to the ISO at an interval of five minutes.[28] While these data will not be used for settlement purposes, customers with behind-the-meter generators are uniquely positioned to manipulate their adjusted Demand Response Baseline. For example, a customer can create a high baseline by just turning off its generator during the period in which meter data are used to establish or adjust the baseline. Data on the output of behind-the-meter generators are needed by the ISO's market monitors to determine whether such "gaming" is occurring.

5. DEMAND REDUCTION OFFERS

Q: Please describe the ISO's proposed tariff provisions regarding day-ahead and real-time energy market Demand Reduction Offers.

A: The ISO's proposed rules require Market Participants to submit a Demand Reduction Offer in the day-ahead and real-time energy markets for each Demand Response Resource in order to be eligible for demand reduction payments.[29] This requirement is comparable to that applied to all other energy resources such as generators. In fact, almost all of the offer requirements and parameters concerning Demand Reduction Offers are comparable to the offer requirements and parameters applied to the Supply Offers submitted by generator owners. The prices, quantities and inter-temporal parameters of each energy resource (including Demand Response Resources and generators) are used by a least-cost, security-constrained algorithm to determine the commitment and dispatch of energy resources to meet regional energy demand.

[28] *See* FIS Appendix E at § 2.1.

[29] *See* FIS Appendix E at § 3.

Q: Are there any important differences in the offer submission requirements and offer parameters between demand resources and generators?

A: Yes. There are two important differences. These include:

1. Demand Reduction Offer prices must be equal to or greater than the Demand Reduction Threshold Price in effect for the day the Demand Reduction Offer is submitted.[30] In contrast, there is no generator threshold price at or above which a generator owner must offer.

2. Market Participants may not self-schedule demand reductions in the day-ahead or real-time energy markets.[31] In contrast, a generator owner may self-schedule upon request to the system operator, who may deny the request.

6. COMPUTATION OF DEMAND REDUCTION THRESHOLD PRICES

Q: Why is there a Demand Reduction Threshold Price and why must the Demand Reduction Offer price be greater than or equal to this price?

A: Order No. 745 requires that demand response providers be paid the market price for energy for demand reductions when their demand resources have the capability to balance supply and demand ***and when payment of the market price for energy to these resources is cost-effective as determined by a consumer net benefits test accepted by the Commission.*** The purpose of the Commission's consumer net benefits test is to ensure that the benefit to consumers of the reduced LMP produced by dispatching demand resources and displacing generation exceeds the cost of dispatching the demand resources.[32] As part of the net benefit test requirement, Order No. 745 requires ISOs and RTOs to "determine on a

[30] *See* FIS Appendix E at § 3(e).

[31] *See* FIS Appendix E at § 3.

[32] Order No. 745 at P 53.

monthly basis under which conditions it is cost-effective to pay full LMP to demand resources."[33] Order No. 745 further defines an approach that could be used to establish monthly Demand Reduction Threshold Prices, which defines the LMP level above which demand reductions from demand resources meets the consumer net benefits test.[34] Order No. 745 states:

> The ISOs and RTOs are to select a representative supply curve for the study month, smooth the supply curve using numerical methods, and find the price/quantity pair above which a one megawatt reduction in quantity that is paid LMP would result in a larger percentage decrease in price than the corresponding percentage decrease in quantity (billing units). Beyond that point, a reduction in quantity everywhere along an upward sloping supply curve would be cost-effective.[35]
>
> *   *   *
>
> [T]he test is to determine where: (Delta LMP x MWh consumed) > (LMPNEW x DR); where LMPNEW is the market clearing price after demand response (DR) is dispatched and Delta LMP is the price before DR is dispatched minus the market clearing price after DR is dispatched.[36]
>
> *   *   *

[33] Order No. 745 at P 78.

[34] Order No. 745 at PP 78-85.

[35] Order No. 745 at fn. 161.

[36] Order No. 745 at fn. 162.

> [T]he threshold point along the supply stack for each month will fall in the area where the supply curve becomes inelastic, rather than the extreme steep portion at the peak or in the flat portion of the supply curve.[37]

By restricting Demand Reduction Offers to prices at or above the Demand Reduction Threshold Price as defined above, "a reduction in quantity everywhere along [the] upward sloping supply curve would be cost-effective"[38] by definition. Conversely, if a demand resource is dispatched at a price below the Demand Reduction Threshold Price, payment of the resulting LMP to the demand response provider would exceed the benefit of the reduced LMP to consumers. Accordingly, Demand Reduction Offers at prices below the Demand Reduction Threshold Price ought to be rejected.

Q: Did the ISO study different approaches to determining Demand Reduction Threshold Prices for the New England electric system?

A: Yes. Because a simple supply curve approach cannot consider numerous complicating factors that affect energy price formation,[39] the ISO was concerned that the approach outlined in Order No. 745 may not produce accurate and robust Demand Reduction Threshold Prices for the New England electric system. If these complicating factors had a significant impact on the relationship between payments to demand response providers and reduction in customer energy payments, the calculation of Demand Reduction Threshold Prices using the supply curve approach might not be accurate enough for practical use.[40]

[37] Order No. 745 at P 80.

[38] Order No. 745 at fn. 161.

[39] Some of these factors include: congestion, the impact of marginal losses, imports and exports, pumped storage, outages, startup costs, generator operating constraints (*e.g.*, minimum generation level), unit commitment, and load.

[40] Order No. 745 also contemplates the potential implementation of a dynamic algorithm in which demand resources are dispatched subject to a more real-time implementation of the Commission's consumer net benefits test. *See* Order No. 745 at P 7. Because such an approach has never been tried and since the integration of the consumer net benefits test is likely to be complex, RTOs/ISOs are required to study the

(continued...)

To validate the supply curve approach outlined in Order No. 745, the ISO retained Charles River Associates ("CRA") to test the method by comparing its results to those of a more sophisticated analysis using an hourly, security-constrained dispatch model (*i.e.,* GE MAPS). Using 2010 data, CRA performed an initial analysis using GE MAPS to simulate the New England wholesale electric system. Next, CRA conducted an analysis using a relatively simple smoothed supply curve approach, with supply curves based on the inputs used in the dispatch model approach. CRA found that the supply curve approach outlined in Order No. 745 produced reasonably accurate and robust results similar to those determined using the much more sophisticated hourly dispatch simulation model. CRA found that developing smoothed supply curves using non-linear regression of real-time generator offers, calculating Demand Reduction Threshold Prices based on those supply curves, and adjusting the thresholds using fuel price indices, is a practical approach that the ISO can use to implement the Commission's consumer net benefits test. CRA's report is attached to my testimony as ***EXHIBIT A.***

Q: How does the ISO propose to "determine on a monthly basis under which conditions it is cost-effective to pay full LMP to demand resources"?[41]

A: In brief, the ISO will follow the three steps indicated in Order No. 745.[42] First, the ISO will select a representative supply curve for the study month. Second, the ISO will determine a smooth approximation to the representative supply curve using numerical methods. Third, the ISO will use the smooth approximation to determine the Demand Response Threshold Price for the representative month.

(...continued)
feasibility of such an approach and file the results with the Commission by September 21, 2012. The ISO will comply with this requirement.

[41] Order No. 745 at P 78.

[42] Order No. 745 at fn. 161.

Q: Regarding the first step, what month does the ISO propose to use "to select a representative supply curve for the study month?"[43]

A. The reference month is twelve months prior to the study month. For example, if the study month is August 2011, the reference month is August 2010.

Q. How will a monthly aggregate supply curve be obtained for a reference month?

A. The ISO will retrieve from the ISO's databases all generation supply offers submitted to the ISO's real-time energy market during the reference month. For each day during the reference month, all generation supply offer blocks (price-MW pairs) will be assembled in ascending price order to produce a market-level, daily supply curve. The market-level, daily supply curve prices will be averaged to obtain the monthly aggregate supply curve for the reference month.

Q: Can the monthly aggregate supply curve for a reference month be shown graphically?

A. Yes. The ISO has assembled monthly aggregate supply curves for the reference months of January 2010 through December 2010. These are shown graphically in ***EXHIBIT B.*** Figure 1 in ***EXHIBIT B*** shows, among other information, the aggregate monthly supply curve for January 2010; Figure 2 shows, among other information, the aggregate supply curve for February 2010; and so forth. Further, the representative supply curve data for January through December 2010 are tabulated, in 25 MW increments, in ***Appendix A*** to ***EXHIBIT B.***

Q: Regarding the second step, please explain how the ISO will determine a smooth approximation of the monthly aggregate supply curve for the reference month.

A. The ISO will begin by determining the relevant sample range of the aggregate monthly supply curve for the reference month. Then the aggregate monthly

[43] *Ibid.*

supply curve for the reference month will be approximated with a smooth mathematical function using regression analysis.

Q: How will the ISO determine the relevant sample range of the aggregate monthly supply curve for the reference month?

A: The relevant sample range will consist of that portion of the aggregate monthly supply curve between a lower sample range price and an upper sample range price. The lower sample range price will equal the product of a lower sample range heat rate value times a reference month fuel price index. The upper sample range price will equal the product of an upper sample range heat rate value times the same reference month fuel price index.

Q: How did the ISO determine the heat rate values it plans to use to calculate the relevant sample range for a reference month?

A: The CRA report's detailed production-cost simulation analyses of the New England electric system (*see* ***EXHIBIT A***) indicated there would be no additional consumer net benefits if a Demand Reduction Threshold Price were set below the price corresponding to a system heat rate of approximately 5,500 BTU per KWh. This can be seen visually in ***EXHIBIT A*** at Figure 3, Figure 4, and the additional figures shown in Appendix A of the CRA report. The CRA report discusses this finding directly on page 10:

> For each month, there is a heat rate threshold below which the net benefits are constant. At those thresholds, demand response is dispatched in every hour, so reducing the threshold further has no impact.

Applying this finding, the portion of the ISO's aggregate monthly supply curve below the point corresponding to a 5,500 BTU per KWh system heat rate is not informative for determining the Demand Reduction Threshold Price. Thus, the regression-based supply curve approximation is restricted to the portion of the monthly aggregate supply curve data above that point.

Q: Did the ISO determine the upper sample range heat rate value similarly?

A: Yes. The CRA report's production-cost simulation analyses indicate that consumer net benefits would *decline* if a Demand Reduction Threshold Price were set above the price corresponding to a system heat rate of approximately 14,000 BTU per KWh. Again, this can be seen visually in ***EXHIBIT A*** at Figure 3, Figure 4, and the additional figures shown in the Appendix A of the CRA report. Thus, the ISO's regression-based supply curve approximation is restricted to the portion of the monthly aggregate supply curve data below that point.

Q: If the supply curve approximation were not restricted to the relevant sample range in this way, would it change the approximation?

A: Yes. It would make the regression-based smooth approximation of the supply curve worse, meaning that the approximated supply curve would not fit the supply offer data as well. Therefore, restricting the analysis to the sample range as described above gives a better estimate of the relevant portion of the supply curve within which the Demand Reduction Threshold Price is located, which in turn gives a better estimate of the Demand Reduction Threshold Price.

Q: Do the upper and lower sample range prices vary among reference months?

A: Yes. Table 1 in ***EXHIBIT B*** shows the upper and lower sample range prices for each month of 2010. The sample range prices vary from month to month because of changes in the fuel price index. The fuel price index utilized is the ISO's existing monthly Forward Reserve Fuel Index, as described in ISO Tariff §§ I.2.2 and III.9.6.2. The Forward Reserve Fuel Index values are publicly available on the ISO's website.

Q: How did the ISO determine a functional form with which to approximate the aggregate monthly supply curve over the relevant sample range?

A: To determine the best functional form, the ISO conducted a separate analysis of smoothed supply curves for the New England electric system. The analysis showed that a functional form equivalent to the one PJM plans to use to estimate its supply curve[44] fits the New England supply offer data well. As a result of this analysis, the functional form that the ISO plans to use to estimate supply curves is the exponential function:

$$P(x) = e^{(Ax + B)} + C,$$

where *P(x)* is the smoothed supply function in which *x* is the supply in MW, *P* is the price in $/MWh, *e* is the mathematical constant 2.718281828…, and *A*, *B*, *C* are the parameters to be estimated through regression analysis. This exponential function produces a curve that is increasing, convex and smooth through its entire range. It is equivalent to the one proposed by PJM in the sense that both the ISO and the PJM functions would produce identical fitted supply curves if applied to the same data. The ISO plans to use this exponential functional form to produce smoothed supply curves for the purpose of estimating Demand Reduction Threshold Prices for New England, unless further research or a future change supply offer behavior reveals that a different function produces better results. As discussed further below, the ISO will post each month on its website, along with the Demand Reduction Threshold Price, the selected functional form and other supply curve data used to determine the Demand Reduction Threshold Price.

Q: Did your analysis identify further considerations that support this smooth approximation method?

A: Yes. The CRA report in ***EXHIBIT A*** developed a functional form for the non-linear regression that combines a cubic component with an exponential component. While that functional form also fits the aggregate monthly supply

[44] *See PJM Interconnection, L.L.C.*, Docket No. ER114106-000, Order No. 745 Compliance Filing (July 22, 2011), p. 18. Posted at: http://www.pjmsettlement.org/~/media/documents/ferc/2011-filings/20110722-er11-4106-000.ashx.

offer data for New England, there are instances in which this more complex functional form could result in multiple Demand Reduction Threshold Prices for the same month. In contrast, the exponential functional form the ISO plans to use is simpler, and always produces a unique Demand Reduction Threshold Price. Because the exponential form always produces a unique Demand Reduction Threshold Price, it precludes any ambiguities that might otherwise arise regarding which of multiple threshold prices should be used.

Q: Are the results of this smooth approximation method shown in *EXHIBIT B*?

A: Yes. As previously noted, Figures 1 through 12 in ***EXHIBIT B*** show the monthly aggregate supply curves for the reference months of January 2010 through December 2010. Super-imposed in each figure is the corresponding smooth approximation to the aggregate supply curve over the relevant sample range. In addition, the precise mathematical values of the parameters *A*, *B,* and *C* that are obtained through regression analysis for each reference month are listed in Table 1 of ***EXHIBIT B.***

Q: On what basis does the ISO conclude that this smooth approximation method fits the data well?

A: Table 1 of ***EXHIBIT B*** reports a statistic labeled "R-Square" (which is also known as "R^2") for each reference month of 2010. R-Square is a standard statistical measure of how well a regression approximation fits the data. The value of R-Square can range from zero to 100 percent. An R-Square value of 100 percent indicates the regression approximation provides a perfect fit to the data, in the sense that all data points lie exactly on the approximating curve. An R-Square value of zero indicates a poor fit, in which the approximating curve is no better than a flat line through the center of the data. As Table 1 indicates, the R-Square value for the ISO's approximation method falls between 98.5% and 99.8% for each reference month. On this basis, the ISO concludes the proposed approximation method fits the data well.

Q: Regarding the third step, how will the ISO use the smooth approximation results to calculate the Demand Reduction Threshold Price for reference months?

A: The ISO will follow the instructions outlined in Order No. 745, which requires the ISO to:

> … find the price/quantity pair above which a one megawatt reduction in quantity that is paid LMP would result in a larger percentage decrease in price than the corresponding percentage decrease in quantity (billing units). Beyond that point, a reduction in quantity everywhere along an upward sloping supply curve would be cost-effective.[45]

In precise terms, this corresponds to the price/quantity pair at which the slope of the smooth approximation function equals P/x, where P is the price (in $ per MWh) and x is the aggregate MW supplied. This price is the Demand Reduction Threshold Price for the reference month.

Q: Is the Demand Reduction Threshold Price for each of the reference months of January through December 2010 represented in EXHIBIT B?

A: Yes. Table 1 in ***EXHIBIT B*** reports the Demand Reduction Threshold Price for the reference months of January through December 2010. They range in value from $55.5 per MWh for January 2010 to $33.8 per MWh for October 2010. ***Table 1*** below summarizes the monthly Demand Reduction Threshold Prices estimated by the ISO for 2010 using the above-mentioned methodology:

[45] Order No. 745 at fn. 161.

Table 1: 2010 Demand Reduction Threshold Prices Estimated by the ISO

Reference Month	Demand Reduction Threshold Price ($/MWh)
January, 2010	**55.5**
February, 2010	**51.4**
March, 2010	**43.6**
April, 2010	**40.1**
May, 2010	**38.6**
June, 2010	**43.2**
July, 2010	**40.9**
August, 2010	**38.9**
September, 2010	**36.0**
October, 2010	**33.8**
November, 2010	**37.7**
December, 2010	**47.0**

Further, ***EXHIBIT B*** includes the data and the estimated supply curves for the 12 month period January through December 2010 that were used to estimate the Demand Reduction Threshold Prices in Table 1.

Q: In order to determine the Demand Reduction Threshold Price for an effective month, will the ISO make any adjustments to the Demand Reduction Threshold Price obtained for the reference month?

A: Yes. The ISO will adjust for the percent change in the fuel price index between the reference month and the effective month. For example, suppose that the fuel price index at the time the ISO calculates the Demand Reduction Threshold Price for an effective month of August 2011 is 10 percent higher than the value of the fuel price index for the corresponding reference month of August 2010. Then the Demand Reduction Threshold Price obtained for the reference month will be increased by 10 percent to obtain the Demand Reduction Threshold Price for the effective month of August 2011.

Q: Is the fuel price index the ISO plans to use for this purpose the same index currently posted on the ISO website and noted previously in your testimony?

A: Yes. The ISO plans to use the existing monthly Forward Reserve Fuel Index for this purpose.

Q: Why does the ISO plan to adjust the Demand Reduction Threshold Price obtained for the reference month by the fuel price index, instead of adjusting the actual Supply Offers during the reference month for subsequent changes in fuel prices?

A: The ISOs proposed method will permit any interested party to re-create the ISO's calculation of the Demand Reduction Threshold Price for the effective month from publicly available data. By contrast, the fuel type of each generator is not available in the ISO's publicly posted Supply Offer data. As such, if the ISO were to adjust the reference month Supply Offer prices for each generator's subsequent change in fuel costs, it would not be possible for any interested party to recreate the ISO's Demand Reduction Threshold Price calculation.

Q: Please summarize the ISO's proposed tariff provisions regarding the computation of Demand Reduction Threshold Prices.

A: The ISO's proposed tariff provisions require that a Demand Reduction Threshold Price be established for each month using a regression-based approximation method on a sampled portion of Supply Offer data (*i.e.*, each price-quantity pair offered in the Real-Time Energy Market) for the historic reference month.[46] Further, the proposed tariff provisions require that the regression produce an increasing, convex, smooth approximation of the supply curve so as to ensure that a unique Demand Reduction Threshold Price is obtained for each month. The Demand Reduction Threshold Price for the historic reference month is the price at which the slope of the smooth approximation function equals P/x, where P is the price (in \$ per MWh) and x is the aggregate MW supplied. The Demand

[46] *See* FIS Appendix E at § 6.

Reduction Threshold Price for the upcoming month is based on the historic threshold price for the same month of the previous year adjusted for any substantial changes in supply availabilities[47] and for differences in fuel price indices between the historic month and the current month.

Q. How would market participants know the precise functional form and other information used by the ISO to determine the smoothed supply curve upon which monthly Demand Reduction Threshold Prices are based?

A. The ISO plans to post on the ISO's website on a monthly basis the supply curve analysis used to determine Demand Reduction Threshold Prices. In addition to the resulting Demand Reduction Threshold Price for the upcoming month, the posting will include:

- The functional form used to establish the smoothed supply curve.
- The historic reference month supply curve data in the form of market-level price/quantity pairs. These data will ***not*** identify the resource associated with each price/quantity pair.
- The relevant sample range, estimated regression coefficients, and associated statistics such as R-Square.
- Any adjustments that were made for significant changes to the composition or slope of the historic monthly supply curves.
- Any adjustments that were made for changes in the fuel price index.

[47] The loss or addition of a major generating resource between the reference month and the effective month that materially changes the shape of the supply curve in the relevant range could affect the resulting Demand Reduction Threshold Price. Should such a resource be lost between the reference month and the effective month, the Supply Offer data associated with that resource would be excluded from the approximation of the supply curve for the historic reference month. Should such a resource be added between the reference month and the effective month, proxy Supply Offer data associated with that resource would be included in the approximation of the supply curve for the historic reference month.

7. PROHIBITION ON SELF-SCHEDULING OF DEMAND REDUCTIONS; RELATED LIMITATIONS

Q: Why are Market Participants not allowed to self-schedule demand reductions in the day-ahead or real-time energy markets?

A: Self-scheduling does not comply with Order No. 745 and, if allowed, would create potential gaming concerns. Accordingly, the ISO's proposed market rules do not permit the self-scheduling of demand reductions.

There are three reasons why self-scheduling does not comply with Order No. 745.

First, self-scheduling would not comply with the Commission's consumer net benefits test as required by Order No. 745. This is because a self-scheduled resource essentially is offered at a $0/MWh price in the Real-Time Energy Market. Because the Demand Reduction Threshold Price will always be greater than $0/MWh, a $0/MWh offer price would violate the Commission's consumer net benefits test required by Order No. 745.

Further, there is no compelling reason to permit self-scheduling of demand reductions given the flexibility afforded Market Participants under the market rules proposed by the ISO. Specifically, the market design provides opportunities for demand response providers to update their Real-Time Energy Market offers after the close of the Day-Ahead Energy Market, and to re-declare the available quantities of demand response for each hour during the Operating Day.

Second, self-scheduling would not facilitate the balancing of supply and demand. In addition to the requirement that payment of the LMP to demand resources be cost-effective as determined by the Commission's consumer net benefits test, Order No. 745 also requires that payment of the LMP be conditioned on the capability of demand resources "to balance supply and demand." The balancing of supply and demand is achieved when each energy resource follows Dispatch Instructions based on the bids/offers submitted to the ISO and on a least-cost, security-constrained dispatch and commitment algorithm administered by the ISO. Self-scheduling, by definition, occurs outside of ISO resource commitment and dispatch, and therefore does not contribute to the balancing of supply and demand. Rather, self-scheduling requires the ISO to readjust the dispatch of other resources to rebalance the system.

Finally and most importantly, self-scheduling would allow a Market Participant to more easily game its Demand Response Baseline. Whenever the demand resource's real-time demand happened to be lower than its calculated baseline, the Market Participant could "self-schedule" a demand reduction and be paid for essentially normally lower consumption that is not in response to higher Real-Time LMPs. For example, if a facility has an unplanned equipment outage, the demand response provider could, if permitted, self-schedule the resulting lower demand and receive a demand reduction payment. If a factory loses an order for its product during the Operating Day, the demand response provider could self-schedule and receive a demand reduction payment even though the output of the factory would have been reduced in any case. If the energy consumption at a facility happens to be running lower than its Demand Response Baseline for whatever reason, the lower demand could be self-scheduled for payment. This is possible because baselines are averages of demands in each time interval from prior days. Normal demand for any interval on any given day will be higher or lower than the calculated baseline on average. Statistically, normal demand will be lower than the calculated baseline about half of the time. A Market Participant could, therefore, exploit the statistical nature of the calculated baseline by "self-scheduling" a demand reduction whenever its normal demand happens to be running lower than average for whatever reason. Self-scheduling, therefore, would facilitate demand reduction payments for normal consumption for about half the days in a year on average.

Q: Why is it *not* appropriate to compensate demand resources when the demands of the underlying customers are running lower than average?

A: According to the Commission, "demand response means a reduction in the consumption of electric energy by customers from their expected consumption ***in response to an increase in the price of electric energy*** or to incentive payments designed to induce lower consumption of electric energy."[48] Therefore, reduced consumption that would have happened anyway and/or that was not in response to higher prices is not demand response and should not qualify for demand reduction payments. Payments for demand reductions that would have happened anyway and/or were not in response to higher prices would result in an unwarranted wealth transfer between different customers and/or between Dispatch Zones.

8. SCHEDULING AND DISPATCHING OF DEMAND RESPONSE RESOURCES.

Q: Please describe the ISO's proposed tariff provisions regarding the scheduling and dispatching of Demand Response Resources.

A: Under these provisions,[49] the ISO would schedule in the Day-Ahead Energy Market, and commit and dispatch in the Real-Time Energy Market, energy resources – including Demand Response Resources and generation resources – needed to balance supply and demand in each time interval. The commitment and dispatch of energy resources would be the result of the ISO's current least-cost, security-constrained dispatch and commitment algorithm as specified in Section III.1.7.6(a) of Market Rule 1, and would be based on the offer parameters submitted by Market Participants for each energy resource. As a result of the Day-Ahead Energy Market clearing process, the ISO will provide an hourly generation and demand reduction schedule for the next Operating Day for each generator resource and Demand Response Resource, respectively. During the Operating Day, the ISO will issue Dispatch Instructions to the Market Participant specifying

[48] Order No. 745 at fn. 2.

[49] *See* FIS Appendix E at § 5.

the expected generation and demand reduction amounts to be produced by each generation resource and Demand Response Resource.

9. DETERMINATION OF REAL-TIME DEMAND REDUCTION OBLIGATION

Q: Please describe the ISO's proposed tariff provisions regarding the determination of the Real-Time Demand Reduction Obligation.

A: The Real-Time Demand Reduction Obligation is a quantity (MW) used in the settlement process and is defined as the actual demand reduction achieved by a Demand Response Resource in real time, adjusted for avoided distribution losses. The ISO will compute a Real-Time Demand Reduction Obligation for each Demand Response Resource for each time interval in which the resource was sent a Dispatch Instruction to reduce its demand.[50]

Because a Demand Response Resource can be an aggregation of Demand Response Assets, the real-time demand reduction of a Demand Response Resource becomes a function of the real-time demand reductions achieved by the individual Demand Response Assets comprising the Demand Response Resource. The real-time demand reduction of a Demand Response Asset is the difference between its adjusted Demand Response Baseline and its metered demand for each interval in which the resource was sent a Dispatch Instruction to reduce its demand.[51]

When a Demand Response Asset's metered demand represents a "net supply" of energy to the grid, the Demand Response Asset has a behind-the-meter generator that is producing more energy than the asset consumes and is injecting energy into the grid. In this circumstance, the Demand Response Asset's actual metered

[50] *See* FIS Appendix E at § 7.

[51] *See* FIS Appendix E at § 7.1.

demand in the interval will be set equal to zero and that value will be used in establishing the real-time demand reduction.[52]

The real-time demand reduction of a Demand Response Resource is the sum of the real-time demand reductions of all the Demand Response Assets comprising the Demand Response Resource.[53] To determine the Demand Response Resource's Real-Time Demand Reduction Obligation, which is the quantity used in the settlement process, the real-time demand reduction of the Demand Response Resource is multiplied by one plus the percent average avoided peak distribution losses.

10. NET SUPPLY OF ENERGY TO THE GRID BY BEHIND-THE-METER GENERATORS

Q: Please explain why the ISO proposes to set a Demand Response Asset's actual metered demand in an interval equal to zero when the asset provides "net supply" of energy to the grid?

A: According to Order No. 745, ISOs that have tariff provisions permitting demand resources to participate in the energy market ***by reducing consumption of electric energy*** from their expected levels in response to price signals must pay these resources the full LMP when these resources have the capability to balance supply and demand and when payment of the market price for energy to these resources is cost-effective as determined by the Commission's consumer net benefits test. A resource providing net supply to the electric system is not reducing consumption of electric energy from the grid. Rather, it is generating energy in excess of its consumption. In other words, a resource providing net supply is not providing demand response – rather, it is providing generation. Accordingly, a resource that injects energy into the electric system cannot be demand response

[52] *See* FIS Appendix E at § 7.3. The amount of energy injected into the grid would be treated as generation resource output, which is compensated at the full LMP like any other generation resource.

[53] *See* FIS Appendix E at § 7.2.

that receives compensation as a demand resource. Rather, the resource is a generator and should be compensated as a generator.

That said, the market rules proposed by the ISO allow a Demand Response Asset with a behind-the-meter generator to receive compensation as demand response if it uses its generation to reduce the demand that is normally served by the grid. For example, say that a Demand Response Asset with a behind-the-meter generator normally consumes 5 MW and typically generates 2 MW. The asset's Demand Response Baseline as measured at its retail delivery point would be negative 3 MW.[54] If the asset increases generation to 5 MW, but does not change its gross energy consumption, the demand served by the grid would decrease to 0 MW. That is, the Demand Response Asset, through the use of its behind-the-meter generation, gave the grid 3 MW of demand response. The ISO's rules would pay for 3 MW of demand response adjusted for avoided distribution losses.

Q: Building from your most recent example above, what would happen if the Demand Response Asset, with a behind-the-meter generator that normally consumes 5 MW and typically generates 2 MW, were to increase generator output to 6 MW in response to price signals?

A: If the asset consumes 5 MW and generates 6 MW, the asset would inject 1 MW of energy into the grid. The meter at the retail delivery point would show a positive 1 MW value.[55] The ISO's proposed rules would set the value at 0 MW in that instance, which would limit the real-time demand reduction amount to 3 MW. The asset was using only 3 MW of energy from the grid, so it can only reduce the demand placed on the grid by 3 MW.

As for the 1 MW of generation supplied to the grid, that amount would receive compensation as a generator, also at the full LMP. To receive compensation for

[54] Negative meter readings indicate load placed on the system. Positive meter readings indicate generation injected to the system.

[55] *Id.*

the 1 MW injected into the grid, the asset would need to be registered with the ISO as a generation resource that could provide energy to the grid.

Q: Why not account for the energy injected into the electric system as a demand reduction, which would result in the same overall payment of the full LMP to the demand resource?

A: If payment were made for energy generated and injected into the grid as though it were demand response, the resulting costs associated with the generation would be misallocated, and the payment would not comply with Order No. 745.

Order No. 745 recognizes that a settlement imbalance is caused by demand response, and addresses the issue by requiring that costs associated with demand response be allocated to purchasers of energy in the relevant market. The settlement imbalance occurs when demand resources are treated as a supply resource, such that the amount of supply that must be paid the LMP exceeds the amount of demand that must pay the LMP. This is because the amount of demand response supplied to the market results in a reduction of demand by the same amount. On the other hand, a MW of generation supplied to the market is always consumed by a MW of demand. That is, generation always equals demand, so generation costs are charged to those who consumed the energy.

If costs of generation were allocated as though they were demand response costs, those consuming the generated energy would receive a windfall at the expense of other customers. For example, if a customer consumes 5 MW and generates 6 MW, 1 MW is injected into the grid. Assume that this customer is part of an aggregation of customers served by a load-serving entity in which all other customers collectively consume 10 MW of energy. By not accounting for the 1 MW of generation injected into the system at that location, the metered energy consumption of the aggregation of customers will be reduced from 10 MW to 9 MW. As a result, the load-serving entity serving the aggregation would be charged for only 9 MW of energy and not the 10 MW actually consumed.

Meanwhile, the cost of 1 MW of generation treated as demand response would be allocated among all other load-serving entities that purchased energy from the market at that time.

Order No. 745 did not authorize a reallocation of generation costs from those who physically consumed the energy to others across the energy market. Rather, Order No. 745 addresses the allocation of costs associated with demand response only – costs associated with the reduction of demand served by the grid and not the costs associated with generation supplied to the grid.

11. INCREASE OF DEMAND REDUCTION OBLIGATION BY AVOIDED PEAK DISTRIBUTION LOSSES

Q: Please explain why the ISO proposes to calculate the Real-Time Demand Reduction Obligation of a Demand Response Resource by increasing its real-time demand reduction by a factor of one plus the percent average avoided peak distribution losses?

A: The real-time demand reduction of a Demand Response Resource is based on measurements taken from meters located at the retail delivery points of each Demand Response Asset comprising the resource. Retail delivery points are located on the utility distribution system and not the wholesale transmission system. However, LMPs are computed at the wholesale transmission system, and include a marginal loss component based on wholesale transmission system losses. A reduction in demand on the distribution system not only reduces the amount of generation dispatched on the wholesale transmission system, but it also avoids the distribution system losses between the retail delivery point and the wholesale transmission system. Therefore, it is appropriate to increase the amount of real-time demand reduction measured at the retail delivery point by the avoided distribution system losses when determining the final settlement for Demand Response Resources.

Accordingly, the ISO proposes to increase the real-time demand amounts by a factor of 1 plus the percent average peak distribution losses when determining a Demand Response Resource's Real-Time Demand Reduction Obligation. The average peak distribution losses in the New England system are about 6.5 percent, so a 1 MW demand reduction achieved at the customer meter would receive compensation of 1.065 MW at the wholesale transmission system level.

Also, the amounts (MW) of a Demand Response Resource's Demand Reduction Offer would also be increased by a factor of one plus the percent average peak distribution losses when determining whether to clear, commit, and/or dispatch a Demand Response Resource in the energy markets. Such treatment is required to bring Demand Response Resources located on the distribution system on par with generation resources located on the wholesale transmission system. This is because reducing 1.000 MW of electrical demand at the distribution system level offsets the need to dispatch 1.065 MW of generation at the wholesale transmission system level. Therefore, a 1.000 MW Demand Response Resource located on the distribution system would be grossed-up to 1.065 MW when deciding whether to clear, commit, and/or dispatch the Demand Response Resource as an alternative to generation.

12. METHODOLOGY FOR, AND COMPUTATION OF, DEMAND RESPONSE BASELINES.

Q: How does the ISO propose to compute Demand Response Baselines?

A: The ISO proposes to use the same basic methodology as that currently used by the ISO to compute Demand Response Baselines, with three modifications.[56] The ISO proposes these modifications to meet the requirement of Order No. 745 that Demand Response Baselines remain accurate so that reductions in a resource's energy consumption can be measured and verified.[57]

[56] *See* FIS ISO Tariff § III.8.

[57] Order No. 745 at P 94.

Q: Why do you propose to use the same basic methodology as that currently used by the ISO to compute adjusted Demand Response Baselines?

A: The ISO's current baseline methodology, combined with a symmetrical baseline adjustment as explained later in the testimony, is one of the best methodologies in use today. A recent study sponsored by the PJM Load Management Task Force found the ISO's baseline methodology performed as well as more sophisticated and administratively complex approaches with respect to accuracy, bias, and variability.[58] Further, by using the ISO's current baseline methodology, the ISO can continue using the infrastructure and software previously developed to compute baselines, which will reduce implementation time and costs.

Q: The ISO also proposes to modify its Demand Response Baseline computation. What are the modifications the ISO proposes?

A: The modifications we propose include:

1. Changing the current asymmetric baseline adjustment to a symmetric baseline adjustment.
2. Implementing a method to reduce baseline bias by requiring that the calculated baseline be periodically refreshed with contemporary meter data.
3. Increasing the number of days meter data are needed to establish an initial Demand Response Baseline for a new Demand Response Resource.

[58] See report posted at: http://pjm.com/~/media/committees-groups/committees/mic/20110510/20110510-item-09a-cbl-analysis-report.ashx. This conclusion was premised on the implementation of a symmetric baseline adjustment. The ISO's present practice is to adjust baselines asymmetrically, which has proven to result in a highly biased baseline. Implementation of a symmetric baseline adjustment improved the ISO's baseline methodology substantially. As explained later, the ISO proposes to modify its baseline methodology to include a symmetric baseline adjustment.

Q: The proposed tariff provisions use a symmetric baseline adjustment rather than an asymmetric baseline adjustment. Before you explain the reason for this, please explain the need for a baseline adjustment.

A: The Demand Response Baseline is an estimate of a consumer's likely energy consumption for each interval of the current Operating Day based on interval meter data from previous days. However, conditions that affect energy consumption in the current Operating Day may vary from the conditions affecting consumption on all previous days from which meter data were used to compute the baseline.

For example, the most obvious and important condition that affects energy consumption from day to day is the weather. On hotter days in the summer, more air conditioning is used, driving expected energy consumption higher. Conversely, expected energy consumption is lower on cooler days in the summer because of lower air conditioning usage. If the baseline were computed using data from cooler days, the baseline for the next Operating Day at the start of a heat wave would under-estimate expected energy usage. Conversely, if the baseline was computed using data during a heat wave, the baseline for the next Operating Day after the heat wave ended would over-estimate expected energy usage.

To account for these normal day-to-day variations, baselines computed as averages of interval meter data from previous days should be adjusted to reflect conditions during the Operating Day. The typical adjustment is based on a comparison between metered demand during an interval in which a demand reduction has not been scheduled in the current Operating Day and the computed baseline (based on data from previous days) for that same interval. If the metered demand is higher than the computed baseline during that interval, the baseline is adjusted upwards. If the metered demand is lower than the computed baseline during that interval, the baseline is adjusted downwards. The precise formula of the adjustment varies among the various RTOs/ISOs. At the present time, the

ISO computes the average difference between a Demand Response Asset's metered demand and its Demand Response Baseline in the two-hour period beginning 2.5 hours prior to the start of the first demand reduction interval in the Operating Day. This average difference is then added to the Demand Response Baseline in each interval. The resulting "adjusted" Demand Response Baseline is the one used to determine the Demand Response Asset's performance and is used in the settlement process.

Q: What is the difference between an asymmetric baseline adjustment and a symmetric baseline adjustment?

A: An asymmetric baseline adjustment is one in which the baseline adjustment is made in only one direction – the ISO's current practice is to adjust the baseline only in the upward direction (that is, to *raise* the expected consumption level for that interval) and not the downward direction. A symmetric adjustment adjusts the baseline in either the upward or downward direction as appropriate.

Q: Why did the ISO implement an asymmetric baseline adjustment in the first place?

A: In 2002, the ISO proposed to implement a comprehensive suite of demand response programs to address system reliability issues and concerns regarding peak energy prices during scarcity conditions. As described at that time, the primary intent of these programs was to provide non-market incentive payments to support an infant industry facing market barriers so as to attract more significant amounts of demand response into the wholesale markets:

> Although a system of price responsive demand in which load would interrupt solely to avoid scarcity Locational Prices would be preferable, NEPOOL has recognized that at this time, incentive payments to load based upon Locational Prices are necessary to attract significant quantities of demand response. The costs created by these incentives are not created by Participants' actions to serve load in the Day-Ahead or Real-Time Markets, as measured by Load Obligations, but rather by a determination that significant quantities of demand response will improve the reliability of the

> transmission system during periods of peak electricity demand. The payments to customers participating in the program are non-market costs that reflect a public policy decision to support an infant industry facing market barriers.[59]

Further, the Commission at that time recognized the need for additional demand response participation in the organized energy markets, and encouraged the ISO to develop incentive mechanisms to encourage customers to reduce demand at times of high energy prices:

> Moreover, since there is very little demand response in the market currently, we believe it would be in the public interest to provide additional incentives for demand response for an interim period in order to encourage customers to reduce demand…. As we underscored in the SMD NOPR, measures that facilitate a robust demand response are essential to the success of competitive wholesale markets.[60]

The policy at that time, therefore, was to encourage demand response, since demand response participation in the markets was limited due to barriers facing the demand response industry. The ISO was aware at that time that a baseline adjustment was needed to address the possibility that customer demand on high price days or during times of reserve shortages and capacity deficiencies was likely to be higher than the estimated baseline. Accordingly, the ISO implemented a baseline adjustment. While the ISO's initial inclination was to adjust baselines symmetrically so as to improve baseline accuracy, some stakeholders argued at that time that customers participating in the Day-Ahead Load Response Program may respond to a day-ahead demand reduction schedule by reducing demand for more hours than that required by their day-ahead demand reduction schedule.

[59] *See* New England Power Pool; FERC Docket No. ER03- -000, Revisions to NEPOOL Market Rule 1 Appendix E Concerning Load Response Program, p. 3 (December 26, 2002).
[60] *New England Power Pool and ISO New England, Inc*., 101 FERC ¶ 61,344 at PP 45-46 (2002).

For example, if a Day-Ahead Load Response Program customer was given a schedule to interrupt demand between 12:00 noon to 5:00 p.m., that customer (particularly an industrial customer that operated in shifts) may decide to call off the entire 9:00 to 5:00 shift. If this were the case, the customer's demand beginning 9:00 a.m. would be lower than its Demand Response Baseline during the period in which the baseline adjustment would be based, resulting in a lower baseline. Therefore, the symmetric adjustment could result in a lower settlement amount and could discourage participation in the Day-Ahead Load Response Program. Given the infancy of the demand response industry at the time, the ISO lacked the experience and data to determine the best ways to estimate Demand Response Baseline accuracy. In light of the ISO's lack of experience and data, and given the Commission's requirement that the ISO encourage customers to participate in demand response programs, the ISO decided to adjust the baseline in only the upward direction – *i.e.*, the baseline was adjusted asymmetrically.

Q: Why does the ISO propose to implement a symmetric baseline adjustment now?

A: First, almost ten years have gone by since the ISO first proposed implementation of comprehensive demand response programs in 2002. At that time, about 100 MW of demand response participated in the wholesale markets. Today, almost 3,600 MW of demand resources have committed to participating in the wholesale markets for the 2014/2015 Capacity Commitment Period. Therefore, the policies and practices implemented to address barriers to demand participation in wholesale markets have worked to an extent. Past practices designed "for an interim period in order to encourage customers to reduce demand"[61] ought to be reexamined to determine their continued necessity.

Second, the ISO now has the data and tools to evaluate baseline accuracy. With the passage of time and with actual program participation, data are now available

[61] Id.

to answer questions regarding baseline accuracy, participant bidding and demand response behavior, and the like.

Third, Order No. 745 requires that the ISO review its demand response measurement and verification protocols so that Demand Response Baselines remain accurate and that reductions in a demand resource's energy consumption can be measured and verified.[62]

Accordingly, the ISO retained KEMA Inc.,[63] to conduct a review of the ISO's current measurement and verification requirements and recommend revisions to the ISO's baseline methodology to ensure that baselines (and the associated demand reduction calculations) remain accurate and unbiased. Three baseline methodologies were analyzed by taking actual interval meter data from customers who did not participate in a demand response program and determining how well the baseline methodology estimated actual consumption for a prospective day using these data.

- The current ISO baseline methodology which uses an asymmetric baseline adjustment (the baseline is adjusted upward but not downward to reflect actual demand prior to the demand reductions);
- The current ISO baseline methodology without any adjustment applied to the baseline (the baseline is not adjusted to reflect actual demand prior to the demand reductions); and
- The current ISO baseline methodology using a symmetric baseline adjustment (the baseline is adjusted upward or downward to reflect actual demand prior to the demand reductions).

[62] Order No. 745 at P 94.

[63] The principal in charge of the KEMA team was Dr. Miriam Goldberg, Senior Vice President - Sustainable Use, KEMA Inc.

KEMA's analysis showed that the ISO's baseline methodology combined with the symmetric baseline adjustment, had the least bias[64] of the three adjustment methods tested (under all scenarios), while the current ISO baseline methodology using the asymmetric baseline adjustment had the most bias. The report detailing KEMA's analysis is attached to my testimony as ***EXHIBIT C***.

This finding is supported by the 2011 baseline accuracy study performed for the PJM Load Management Task Force.[65] This study evaluated the accuracy of twelve baseline methods using two years of demand data from about 20,500 C&I customers in the PJM service territory including over 4,500 emergency and economic demand response participants. The ISO baseline methodology was included as part of the study and was evaluated in terms of accuracy, bias and variability when used in two forms: without an adjustment and with a symmetric adjustment. This study concluded that the ISO baseline methodology, with the symmetric adjustment, was one of the top performers under all three evaluation criteria.

Accordingly, the ISO's proposed rules specify that the Demand Response Baseline include the symmetric baseline adjustment.

[64] Baseline bias indicates a systematically over- or under-estimated baseline.

[65] See report posted at: http://pjm.com/~/media/committees-groups/committees/mic/20110510/20110510-item-09a-cbl-analysis-report.ashx. It is important to note that the current ISO baseline methodology with asymmetric adjustment was not included in the PJM study. The asymmetric adjustment method was deliberately omitted from the PJM study, because the project sponsors and analysts felt the asymmetric adjustment method, by its very nature, would result in significant bias in the baseline calculations.

Q: Are there any other Demand Response Baseline provisions that will be implemented under the full integration of demand resources in wholesale energy markets that address the possibility that some participating customers could be disadvantaged by the symmetric baseline adjustment, particularly those who need a long "start-up time" to achieve a scheduled demand reduction?

A: Yes. Under the fully integrated solution,[66] a demand response provider can submit as part of its Demand Reduction Offer a "Demand Response Resource Startup Time," which is the time required from the point at which the resource starts reducing demand in response to a Dispatch Instruction and the time the resource achieves the demand reduction amount specified in the Dispatch Instruction. Because full integration includes this inter-temporal parameter in the Demand Reduction Offer, the proposed rules also recognize a Demand Response Resource Start-Up Time when determining the period upon which the Demand Response Baseline adjustment ought to be based. Specifically, the adjusted Demand Response Baseline would be based on the average difference between the Demand Response Asset's metered demand and its Demand Response Baseline in the intervals during the two-hour period – beginning two hours *plus* the Demand Response Resource Start-up Time – prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the resulting Demand Response Baseline.

Recognizing a resource's Start-up Time in determining the intervals upon which to base the adjusted Demand Response Baseline addresses the unintended consequence of adjusting the baseline downward given demand reduction activities prior to the time demand is scheduled to be reduced. The ISO will be able to implement this feature when the full integration of demand response into the wholesale energy markets has been accomplished.

[66] *See* FIS Appendix E at § 3.2(d).

Q: Prior to full integration of demand resources into wholesale energy markets, is it possible that a subset of participants consisting of industrial customers whose employees work in shifts could be disadvantaged by the symmetric baseline adjustment?

A: It is possible, but we have not found any data supporting the notion that some participants actually call off entire shifts in response to a day-ahead demand reduction schedule. On the contrary, practically all of the Demand Reduction Offers submitted to the ISO in the current Day-Ahead Load Response Program reflect the minimum offer amount of 100 kW at the minimum offer price, and do not specify a minimum interruption duration.[67] One would expect that an industrial customer who would potentially call off an entire shift if its Demand Reduction Offer were cleared by the ISO would bid the amount of demand reduction associated with the shift reduction, would bid a higher price to reflect the opportunity cost of the shift reduction, and would include in its offer a minimum interruption duration to reflect the multi-hour nature of the shift reduction. However, no such offers have been submitted to the ISO, which casts doubt on claims that industrial customers would potentially call off an entire shift if its Demand Reduction Offer were cleared by the ISO.

Accordingly, we propose the symmetric baseline adjustment mechanism for all demand resources given that the KEMA analysis demonstrated that an asymmetric baseline adjustment results in biased baselines.

Given the theoretical possibility that industrial customers whose employees work in shifts could be disadvantaged by the symmetric baseline adjustment, however, the ISO will continue to work with Market Participants to quantify the potential

[67] The current Day-Ahead Load Response Program allows program participants to specify a minimum interruption duration of up to four hours. If an offer specifies a four-hour minimum interruption duration, Day-Ahead LMPs must be sufficiently high during any four-hour period during the Operating Day so that the participant recovers its Demand Reduction Offer price times the offer amount for the four-hour period.

baseline bias created by a symmetric baseline adjustment for customers that may cancel entire shifts in response to a day-ahead schedule. To the extent such customers exist and the baseline bias is significant, the ISO will analyze alternative baseline adjustment mechanisms to address these customers, and define criteria to determine which customers should qualify for the alternative baseline adjustment mechanism.

Q: Why does the ISO need to ensure that the calculated baseline is periodically refreshed with contemporary meter data?

A: KEMA's baseline analysis in ***EXHIBIT C*** revealed that baseline accuracy and bias is directly impacted by the frequency with which demand resources clear in the energy market. Under the ISO's current baseline methodology, metered demand data from non-cleared days is used in the baseline calculation and data from cleared days is excluded. As the number of cleared days in a period increases, necessarily the number of non-cleared days in the same period decreases. This reduces the amount of recent metered demand data that can be used in calculating the baseline.

The Demand Reduction Threshold Prices calculated by CRA for 2010 are substantially lower than the monthly minimum offer prices used in the Day-Ahead Load Response Program for 2010. Had the Demand Reduction Threshold Prices calculated by CRA for 2010 been used as the Day-Ahead Load Response Program's minimum offer prices, an offer to reduce demand at the minimum offer price would have cleared every day for many months on end in 2010.[68]

KEMA's analysis showed that, if demand resources offer persistently at the Demand Reduction Threshold Price − which is based on the Commission's consumer net benefits test − these offers would clear virtually every day of the

[68] At the present time, practically all DALRP offers submitted to the ISO are at the minimum 0.1 MW demand reduction amount and the minimum allowed offer price.

year, which would result in inaccurate and biased baselines. Excluding the cleared days from the baseline computation could thus make the data used to establish the baseline months old – for example, the baseline used to estimate expected demand absent demand reductions in response to price signals in the fall and winter could be based on summer meter data. Since summer demand is generally higher and more volatile than fall and winter demand, a baseline based on meter data from the summer would allow a demand resource to claim and be paid for demand reductions in the fall and winter even though the resource took no action to reduce its demand.

Order No. 745 requires the ISO to develop measurement and verification protocols to ensure that appropriate baselines are established. Accordingly, the ISO proposes a baseline methodology that mitigates the baseline inaccuracy and bias problems brought on by frequent clearing. In addition to reflecting a symmetric baseline adjustment, the proposed rules incorporate a methodology to refresh the baseline with recent meter data so that calculated baselines reflect normal customer demand shapes in the immediate time period. So that the baseline reflects the expected demand of a participating customer absent demand reductions in response to price signals, the proposed rule is designed to ensure that data from the immediate time period are used to estimate baselines.

Q: What methods did the ISO explore to ensure that data from the immediate time period are used to estimate baselines?

A: The ISO explored two methods. The first method was called the Baseline Accuracy Price method. The Baseline Accuracy Price method uses price to determine when a resource's metered demand data should be included in the baseline calculation by comparing a resource's offer price and LMP to the Baseline Accuracy Price. The Baseline Accuracy Price would be established at a level to make certain that a sufficient number of days of recent metered demand data are used in the baseline calculation to ensure the baseline remains accurate and unbiased. If a resource's offer clears and the LMP in the cleared interval is greater than the Baseline Accuracy Price, then the resource's metered demand data for that day would be *excluded* from the baseline calculation. However, if the resource's offer clears and the LMP in the cleared intervals is less than or equal to the Baseline Accuracy Price, then the resource's metered demand data for that day would be *included* in the baseline calculation.

Q: Does the ISO propose to implement the Baseline Accuracy Price method?

A: No. When the ISO explained the Baseline Accuracy Price method during the stakeholder process, Market Participants raised two primary concerns:

1. The Baseline Accuracy Price method would effectively introduce a second, higher threshold price below which Market Participants may be unwilling to offer. Market Participants asserted that the Baseline Accuracy Price method would subvert the intent of Order No. 745.

2. The Baseline Accuracy Price method would be indiscriminately applied to all resources. The Baseline Accuracy Price method would be applied regardless of how a resource previously offered and cleared. For example, a resource that had never cleared or interrupted could, under the Baseline Accuracy Price method, have metered demand data included in its baseline calculation on the first day it cleared if the LMP was less than the Baseline Accuracy Price – while the resulting baseline would not be used to compute the demand reduction amount achieved on the first day, it would be used to compute demand reduction amounts on subsequent days. Metered demand data on a cleared day would be included in the baseline calculation, despite the fact that the resource already had an accurate and unbiased baseline. Similarly, a resource with a baseline that is <u>not</u> contemporary (because it cleared on many consecutive days) could not, under the Baseline Accuracy Price method, have metered demand data included in the baseline calculation if the LMP is greater than the Baseline Accuracy Price.

Q: Given these concerns, how does the ISO propose to ensure that data from the immediate time period is used to estimate baselines?

A: To address stakeholder concerns, the ISO developed and evaluated a second method to achieve baseline accuracy. The ISO asked KEMA to evaluate an alternative baseline refreshment mechanism using an administrative rule that is independent of the resource's offer price or the LMP. The alternative approach is called "X of Last 10 Days." While the criteria for refreshing the baseline with recent data differs between the two methods, the Baseline Accuracy Price and "X of Last 10 Days" methods both include in the baseline calculation metered demand data from some days on which the resource offers and clears.

Under the "X of Last 10 Days" method, the decision to include a resource's metered demand data in the baseline calculation on any given day is made by counting the number of days, over the past 10 days of the same day type (*e.g.*, weekdays), on which metered demand data was included in the baseline calculation. If the number of "included" days over the past 10 days is less than the minimum criteria, then today's metered demand data are included in the baseline calculation regardless of whether the resource cleared for today or not.

KEMA compared the "X of Last 10 Days" method's effect on baseline accuracy with the Baseline Accuracy Price method using the same data, baseline adjustment scenarios, average median relative error methodology, and assumptions as in the analysis used in evaluating the Baseline Accuracy Price method. This facilitated an "apples-to-apples" comparison of the Baseline Accuracy Price and "X of Last 10 Days" refreshment methods. To test the sensitivity of the "X of Last 10 Days" method to the number of included days, KEMA varied the minimum criteria or "X" from 1 to 5 days. ***Table 2*** provides the average median relative error analysis under the various scenarios tested.

Table 2: Comparison of Average Median Relative Error Results
Baseline Accuracy Price Versus X of Last 10 Days Methods

Adjustment Type	Without BAP	With BAP	At least x of last 10 days included in				
			1	2	3	4	5
Asymmetric	19.00%	10.80%	14.20%	11.70%	9.50%	8.10%	7.00%
Unadjusted	17.00%	8.40%	11.90%	9.40%	7.00%	5.60%	4.60%
Symmetric	6.00%	**2.90%**	4.30%	3.50%	**2.70%**	2.30%	1.80%

The ISO initially proposed to stakeholders the Baseline Accuracy Price, along with a symmetric baseline adjustment, because it significantly reduced the average median relative error. The results of KEMA's new analysis show that a "3 of Last 10 Days" refreshment method, along with a symmetric baseline adjustment, can achieve a slightly better result than the Baseline Accuracy Price.

Accordingly, the ISO's proposed market rules includes the use of the "3 of Last 10 Days" baseline refreshment method. In addition to being slightly more accurate than the Baseline Accuracy Price mechanism, the "3 of Last 10 Days" is transparent and easier to administer for both Market Participants and the ISO compared to the Baseline Accuracy Price approach, which requires periodic calculations and updates. Finally, the "3 of Last 10 Days" method does not introduce another price threshold in addition to the Demand Reduction Threshold Price.

Q: Why do you propose to increase the number of days needed to establish an initial Demand Response Baseline?

A: The "3 of Last 10 Days" methodology requires that, at some point, at least 10 days of meter data be used to develop the Demand Response Baseline in the first place. Further, increasing the sample size upon which to estimate the expected demand of a participating customer absent demand reductions in response to price signals always improves the statistical confidence of the estimate. While more data could be used to develop the initial Demand Response Baseline, requiring more data to establish the initial Demand Response Baseline also requires that the new participant not respond to price signals during initial baseline development, which delays participation in the market. Data from 10 continuous days of the same day-type is sufficient to establish a reliable Demand Response Baseline.

13. ENERGY MARKET SETTLEMENT

Q: Please describe the ISO's proposed tariff provisions regarding energy market settlement.

A: Energy market settlement of a Demand Response Resource is identical to the settlement of any other energy resource. In the Day-Ahead Energy Market, a Market Participant with a Demand Response Resource will be paid for its Day-Ahead Demand Reduction Obligation multiplied by the Day-Ahead LMP for the Dispatch Zone or Node at which the resource is located.[69] The Day-Ahead Demand Reduction Obligation is the sum of the hourly demand reduction amounts of the Demand Response Assets comprising 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.

In the Real-Time Energy Market, a Market Participant with a Demand Response Resource will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the hourly Real-Time LMP for the Dispatch Zone or Node at which the resource is located.[70] The payment for the amount by which the Real-Time Demand Reduction Obligation exceeds the Day-Ahead Demand Reduction Obligation in an hour would be set to zero if the Real-Time LMP for that hour is less than the Demand Reduction Threshold Price. This is done to recognize the payment restrictions imposed by the Commission's consumer net benefits test.

[69] *See* FIS Appendix E at § 9.1.

[70] *See* FIS Appendix E at § 9.2.

Further, as with other resources participating in the energy market, Market Participants with Demand Response Resources are eligible for Net Commitment Period Compensation ("NCPC") credits if they are following Dispatch Instructions.[71] A Market Participant with a Demand Response Resource is ineligible for NCPC credits and may be assessed NCPC charges if the resource is not operating within the acceptable dispatch tolerance. A resource is operating within the acceptable dispatch tolerance when the resource is operating within 10% above or below the resource's Dispatch Instruction in every five-minute interval in an hour. A resource that fails the 10% dispatch tolerance test will be relieved from NCPC charges if during the entire hour the resource operates within 5% above or below the resource's Dispatch Instructions during the hour on average. These requirements are consistent with those for the payments/charges of NCPC to generators.

14. COST ALLOCATION

Q: How does the ISO propose to allocate costs associated with Demand Response Resources participating in the energy markets?

A: The ISO proposes that charges or payments resulting from real-time demand reductions produced by Demand Response Resources be allocated on an hourly basis proportionally to Real-Time Load Obligation on a system-wide basis, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Dispatchable Asset Related Demand postured by the ISO.[72]

Excluding the Real-Time Load Obligation incurred at all External Nodes is appropriate to avoid restricting the trade of energy between regions and to avoid taxing other regions for demand response that primarily benefits the host region. Excluding Real-Time Load Obligation incurred by Dispatchable Asset Related

[71] *See* FIS Appendix E at § 9.4.

[72] *See* FIS Appendix E at § 9.3.

Demand postured by the ISO is appropriate given that such demands are not charged the LMP for the energy consumed;[73] therefore, these demands do not benefit from changes in LMP caused by the dispatch of Demand Response Resources.

This allocation is consistent with the Commission's requirement that the costs associated with demand response compensation be allocated proportionally to all entities that purchase from the relevant energy market in the areas where the demand response reduces the market price for energy at the time when the Demand Response Resource is committed or dispatched. In New England, a system-wide allocation is appropriate given that transmission constraints generally are not severe at this time; hence, demand reductions in one location tend to lower LMPs in multiple locations. Further, demand resources are distributed throughout the region, making simultaneous demand reductions in multiple zones relatively common, so that LMPs from dispatched demand resources are likely to affect LMPs across the region even where binding transmission constraints do arise. Finally, the analysis to discern how a demand reduction in one location affects (or does not affect) LMPs in other locations is extremely complex and, for the reasons stated above, appears to be unnecessary.

[73] These demands represent the pumps at pumped-storage hydroelectric units. The ISO may periodically dispatch these pumps when the LMP is higher than the Demand Bid associated with the pumping phase of these units. The ISO would require such pumping in anticipation of energy needs later in the day. When these pumps are postured by the ISO, the Market Participant is charged their Demand Bid price and not the LMP for the energy used to pump the pumped-storage hydroelectric unit.

C. TARIFF CHANGES IMPLEMENTING THE TRANSITIONAL SOLUTION

1. OVERVIEW

Q: Given that the fully integrated approach would not be implemented until June 1, 2015, the ISO has proposed a new, transitional solution to replace its current price-response programs. Please summarize the ISO's proposed transitional solution.

A: Given that the fully integrated approach would not be in place until June 1, 2015, the ISO proposes to implement a new, transitional solution that can be implemented expeditiously and inexpensively by building upon the infrastructure developed for the current Day-Ahead Load Response Program that is expiring as of May 31, 2012. While the transitional solution would re-use much of the existing price-response program infrastructure, certain tariff provisions are needed to comply with Order No. 745. If the ISO's proposed transitional approach is accepted by the Commission, it would be implemented on June 1, 2012, the date that the current Day-Ahead Load Response Program and Real-Time Price Response Program are scheduled to expire. The transitional solution would remain in place until June 1, 2015, the date on which the fully integrated solution would go into effect.

Q: Please explain how the transitional solution complies with Order No. 745 and how it differs from the existing programs.

A: Certain aspects of the ISO's current price-response programs already comply with Order No. 745. For example, the current programs already pay the full LMP for reductions in energy usage and require that Demand Reduction Offers be at or above a threshold price. However, compliance with Order No. 745 requires:

- **Changing the program threshold price to implement the Commission's consumer net benefits test.** The ISO proposes to compute Demand Reduction Threshold Prices in the same manner as in the fully integrated solution. Demand Reduction Offers submitted into the transitional program must be at or above the Demand Reduction Threshold Price.

- **Improving the existing baseline methodology to account for changes in the program threshold price so that baseline accuracy is maintained while allowing for potentially more frequent clearing of Demand Reduction Offers.** The changes to the existing baseline methodology previously described above with respect to the fully integrated solution would also be implemented for the transitional solution.

- **Reviewing and modifying the compensation approach to reward quantities of demand response delivered in real time that are consistent with the amounts offered and scheduled in response to LMPs.** The current price-response programs allow for voluntary, unpredictable, self-scheduled response, and encourages demand resources to deliver quantities of demand response that substantially diverge from the quantities offered and scheduled. This does not facilitate the balancing of supply and demand. To facilitate the balancing of supply and demand as an alternative to a generation resource, demand response providers must be given the incentive to provide realistic demand reduction offers reflecting the true capability of their resources, and to interrupt demands consistent with the amounts scheduled and/or dispatched by the ISO.

- **Implementing the new cost allocation approach.** At the present time, the costs associated with payments to demand response providers are allocated to Network Load on a system-wide basis. Order No. 745 requires that such costs be allocated "proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand resource is committed or dispatched."[74]

[74] Order No. 745 at P 102.

2. REGISTRATION OF DEMAND RESPONSE RESOURCES

Q: How does the proposed transitional solution differ from the fully integrated solution regarding demand response resource registration?

A: In the fully integrated approach, Demand Reduction Offers are associated with Demand Response Resources, which may consist of individual end-use customers or of aggregations of end-use customers located within the same Dispatch Zone. In the transitional solution,[75] Demand Reduction Offers are associated with Real-Time Demand Response Assets,[76] which are individual end-use customers only. The ISO's current price-response program infrastructure, upon which the transitional solution will be based, is not able to accommodate aggregations of assets. The ISO plans to address this limitation when developing the infrastructure for the fully integrated solution – that is, the fully integrated solution will be able to accept offers associated with demand resources consisting of an aggregation of assets.

3. METERING AND COMMUNICATIONS

Q: How does the proposed transitional solution differ from the fully integrated solution with respect to metering and communication?[77]

A: In the fully integrated approach, the Market Participant will be required to use a remote terminal unit to communicate telemetry information to the ISO and receive Dispatch Instructions from the ISO – that is, full integration requires full two-way, real-time communication between the ISO and a Market Participant with demand resources. However, the current price-response program infrastructure upon which the transitional solution will be based is not able to

[75] *See* Appendix E for the transitional solution ("TS Appendix E") at § 1.

[76] Prior to the implementation of the fully integrated solution, an individual end-use customer that participates in the wholesale electricity markets is called a "Real-Time Demand Response Asset," which is a defined term in the ISO's present tariff. The ISO's present market rules allow Real-Time Demand Response Assets to participate in the Day-Ahead Load Response Program and as part of a Real-Time Demand Response Resource in the Forward Capacity Market. Real-Time Demand Response Assets would be allowed to participate in the transitional solution once implemented.

[77] *See* TS Appendix E at § 2.

send energy market Dispatch Instructions to participating Real-Time Demand Response Assets. The infrastructure needed to send demand resources energy market Dispatch Instructions as well as receive real-time telemetry information will be developed for the fully integrated solution.

4. DEMAND REDUCTION OFFERS

Q: How do Demand Reduction Offers for the transitional solution differ from those made under the fully integrated solution?

A: In the fully integrated solution, the ISO's proposed rules require Market Participants to submit a Demand Reduction Offer in the day-ahead and real-time energy markets for each Demand Response Resource in order to be eligible for demand reduction payments. This requirement is comparable to that applied to all other energy resources. In the transitional solution, the ISO is able to accept Demand Reduction Offers only on a day-ahead basis, due to infrastructure limitations of the current Day-Ahead Load Response Program.

Further, the current Day-Ahead Load Response Program allows for only one price/demand-reduction quantity pair for each asset,[78] whereas the fully integrated solution permits up to 10 price/demand-reduction quantity pairs for each resource. A price/demand-reduction quantity pair is the primary component of a Demand Reduction Offer, which indicates the amount of energy consumption in a time interval the asset or resource is willing to reduce from the grid if paid the price denoted in the offer.

Finally, the current Day-Ahead Load Response Program allows program participants to submit two other bid parameters – a curtailment initiation price, which enables the Market Participant to declare a fixed cost that must be recovered per interruption/start-up, and up to a four-hour minimum interruption duration period, which enables the Market Participant to state the minimum

[78] *See* TS Appendix E at § 3.1.

amount of time for which the energy consumption of the Real-Time Demand Response Asset must be interrupted if scheduled.[79] These parameters are inter-temporal bid parameters comparable to, but simpler than, those used by generators, which will carry forward for use in the transitional solution. By contrast, the fully integrated solution will include a wide array of additional bid parameters comparable to the array of bid parameters currently available to generation resources.

The continued use of the minimum interruption duration bid parameter in the transitional solution could result in clearing and scheduling a Demand Reduction Offer in hours where the LMP falls below the Demand Reduction Threshold Price. However, Demand Reduction Offer prices must be at or above the Demand Reduction Threshold Price. Therefore, the ISO would clear an offer with a minimum interruption duration greater than one hour for an hour in which the LMP was below the Demand Reduction Threshold Price only if the LMP in other hours in which the offer cleared exceeded the Demand Reduction Threshold Price by an equal or greater amount. For example, take a Demand Reduction Offer made at the Demand Reduction Threshold Price of $50/MWh with a two-hour minimum interruption duration. The clearing algorithm would accept this offer in an hour with, say, a $45/MWh LMP only if the LMP in the preceding or subsequent hour was greater than or equal to $55/MWh. What this means is that the net loss in consumer value in the hours in which the LMP is below the Demand Reduction Threshold Price is offset by net gains in consumer value in other hours in which the LMP is above the Demand Reduction Threshold Price.

Order No. 745 does not address the application of the consumer net benefits test in the context of Demand Reduction Offers that include inter-temporal parameters. However, the ISO believes that its proposed approach to the clearing of offers with a minimum interruption duration greater than one hour is compliant

[79] *See* TS Appendix E at § 3.2.

with the spirit and direction set by Order No. 745. Further, this approach is comparable to the dispatch of generators with a minimum run time – generators with a minimum run time may be dispatched during hours in which the LMP falls below their offer price if LMPs in other hours in which the generator cleared is above the offer price by an equal or greater amount.

5. CONSUMER NET BENEFITS TEST

Q: How does the transitional solution comply with Order No. 745's requirement for a consumer net benefits test?

A: The transitional solution requires that Demand Reduction Offer prices must be equal to or greater than the Demand Reduction Threshold Price in effect for the day the Demand Reduction Offer is submitted.[80] The ISO proposes to compute the Demand Reduction Threshold Price in the same way as previously described for the fully integrated solution.

6. CLEARING AND SCHEDULING DEMAND REDUCTION OFFERS

Q: How does the process for clearing and scheduling Demand Reduction Offers in the day-ahead and real-time energy markets in the transitional solution differ from that of the fully integrated solution?

A: In the fully integrated solution, offers from Market Participants with Demand Response Resources are considered in the security-constrained, economic dispatch algorithm along with all other energy resources. The energy resources (generation and demand response) that contribute to the optimal, least-cost solution are cleared and dispatched. LMPs are set by the marginal resources cleared or dispatched by the ISO. In the fully integrated solution, the marginal resource that sets price could be a Demand Response Resource.

[80] *See* TS Appendix E at § 3.1.

In the transitional solution, the Day-Ahead Energy Market solution is derived before consideration of Demand Reduction Offers.[81] The resulting Day-Ahead LMPs are then used to determine the clearing of Demand Reduction Offers in the Day-Ahead Energy Market. Real-Time Demand Response Assets whose offer costs (as defined by the Demand Reduction Offer) are recovered from payment of the resulting Day-Ahead LMPs are cleared and scheduled. As previously mentioned, however, there is no real-time dispatch of Real-Time Demand Response Assets in the transitional solution. Accordingly, the transitional solution is not an ideal, end-state solution – the ideal, end-state solution is that represented by the fully integrated solution. However, the transitional solution does provide incentives for participants to reduce demands in response to LMPs, and does provide price benefits to entities that purchase energy. To the extent participants reduce demand in response to incentive payments, the lowered real-time demand tends to reduce real-time LMPs, and real-time LMPs and day-ahead LMPs tend to converge. Accordingly, the transitional solution is consistent with the direction and spirit set out by Order No. 745. Further, providing a transitional program with appropriate incentives will motivate demand response providers to prepare for the implementation of the fully integrated solution.

7. REAL-TIME DEMAND REDUCTIONS WHERE DAY-AHEAD OFFER NOT ACCEPTED

Q: Given that the current Day-Ahead Load Response Program upon which the transitional solution is based allows Market Participants to submit offers on a day-ahead basis only, is there an opportunity for Market Participants to provide demand reductions in real time if the participant's Demand Reduction Offer was not accepted in the Day-Ahead Energy Market?

A: Yes. One of the additional features included in the transitional solution, which does not exist in the current Day-Ahead Load Response Program, is the ability for Market Participants to receive payments at the real-time LMP if the participant's

[81] *See* TS Appendix E at § 4.

Demand Reduction Offer was not accepted in the Day-Ahead Energy Market[82]. Day-Ahead Demand Reduction Offers are not accepted in the Day-Ahead Energy Market when day-ahead LMPs are not sufficiently high to clear the offer. However, if real-time LMPs escalate above day-ahead LMPs and the Demand Reduction Offer becomes economic in real time, the demand resource should have the opportunity to reduce demand and be paid the real-time LMP for that reduction. Accordingly, the transitional solution rules provide for payment to the Market Participant of the real-time LMP for reductions in demand achieved in real time when the hourly real-time LMP published on the ISO's website exceeds the price in the Demand Reduction Offer.

8. INCENTIVES FOR MARKET PARTICIPANTS TO FOLLOW THEIR CLEARED DAY-AHEAD DEMAND REDUCTION SCHEDULES; 200% CAP

Q: Please explain the ISO's concerns regarding the incentives for Market Participants, in the transitional solution, to follow their cleared day-ahead demand reduction schedules, based on the ISO's experience with the Day-Ahead Load Response Program.

A: In both the transitional and fully integrated solutions, the Real-Time Demand Reduction Obligation is a quantity (MW) used in the settlement process and is defined as the demand reduction achieved by a demand response asset or resource in real-time adjusted for avoided distribution losses. However, in the fully integrated solution, a Market Participant with a Demand Response Resource is eligible to receive Net Commitment Period Compensation ("NCPC") payments if the resource follows Dispatch Instructions, and is potentially assessed NCPC charges if the resource does not operate within acceptable dispatch tolerances. The "carrot-stick" nature of NCPC payments and charges give energy resources additional incentives to follow Dispatch Instructions. On the other hand, NCPC cannot be paid or charged to those participating in the transitional solution given

[82] *See* TS Appendix E at § 5.

that Real-Time Demand Response Assets do not participate directly in the energy markets. Accordingly, another approach is needed to ensure that Real-Time Demand Response Assets participating in the transitional solution follow their cleared day-ahead demand reduction schedule.

Implementing an approach to encourage Market Participants with Real-Time Demand Response Assets participating in the transitional solution to follow their cleared day-ahead demand reduction schedule is particularly important given the bidding/demand reduction behavior observed in the Day-Ahead Load Response Program to date. Those participating in the current Day-Ahead Load Response Program almost always offer 100 kW of demand reduction on a day-ahead basis, but then interrupt demand in real time in what appears to be a random pattern that bears no resemblance to the amount cleared day-ahead and does not appear to be in response to real-time LMP levels. Often, the amount of demand reduced in real time is several orders of magnitude higher than the amount in the cleared Demand Reduction Offer. Such behavior certainly does not facilitate the balancing of supply and demand as an alternative to a generation resource. Market Participants with Real-Time Demand Response Assets will be ill-prepared to function under the fully integrated approach if they are not given the incentive to learn of their customer's demand reduction capabilities during the transition period.

Q: What has been included in the proposed rules to address these concerns?

A: Rather than applying a penalty for demand response not following its demand reduction schedule, the ISO proposes in the transitional solution rules to cap the Real-Time Demand Reduction Obligation of a Real-Time Demand Response Asset to 200% of the associated Demand Reduction Offer amount adjusted for avoided distribution losses.[83] Such an approach is easy and transparent to administer, and would encourage more accurate day-ahead bidding in the transitional solution.

[83] See TS Appendix E at § 8.4.

Q: What factors affect the setting of the level of the cap, and how was an appropriate level for the cap determined?

A: Setting the cap on the Real-Time Demand Reduction Obligation of a Real-Time Demand Response Asset requires careful consideration. If the cap is set too high – under the current Day-Ahead Load Response Program there is no cap – then it would not give demand response providers the incentive to submit Demand Reduction Offers reflecting the true capability of their assets. On the other hand, if the cap is set too low, the participation of demand resources that have high variability in terms of how much demand reduction can be delivered at different times of the day could be impaired because the transitional solution will not allow demand response providers to specify hourly bidding parameters to reflect the different demand reduction quantities available at different hours.

Analysis conducted by the ISO indicates that a cap of 200% is appropriate. The ISO examined hourly demand reductions from assets participating in the Day-Ahead Load Response Program in 2010. The ISO limited its analysis to assets with hourly demand reductions greater than 100 kW and less than 10 MW. This filter was intended to eliminate the "noise" associated with very small demand reductions and exclude reductions from larger assets that generally produce demand reductions by injecting energy into the grid using behind-the-meter generation. The average hourly demand reduction from the remaining 826 assets was 320 kW. This analysis showed that the daily variability in hourly demand reductions (measured as the ratio of the maximum demand reduction to the minimum demand reduction in a day) was greater than the hourly variability observed in the class average demand shapes of typical commercial and industrial customers or New England system demand shapes.[84] A cap of 204% would

[84] Indeed, the ratio of the maximum demand reduction to the minimum demand reduction on any day ranged from a minimum of 1.00 to a maximum of 69.86.

accommodate the *average* variability in hourly demand reductions observed in the Day-Ahead Load Response Program in 2010.[85]

Based on this analysis, the proposed transitional solution includes a cap on the Real-Time Demand Reduction Obligation of a Real-Time Demand Response Asset equal to 200% of the associated Demand Reduction Offer amount adjusted for avoided distribution losses.

9. BASELINE COMPUTATION

Q: How does the ISO propose to compute Demand Response Baselines for the transitional solution?

A: Under the proposed rules, the same baseline modifications described for the fully integrated solution will be implemented for the transitional solution.[86] That is, the ISO proposes to use the same basic methodology as that currently used by the ISO to compute Demand Response Baselines, with three modifications so that reductions in a resource's energy consumption can be measured and verified.[87] The proposed modifications include:

1. Changing the current asymmetric baseline adjustment to a symmetric baseline adjustment.
2. Implementing a method to minimize baseline bias by requiring that the calculated baseline be periodically refreshed with contemporary meter data using the "3 of Last 10 Days" baseline refreshment method.

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[85] Class average load shapes of typical commercial and industrial customers in New England and the New England system load shape during hours ending 0800 to 1800 in year 2010 show that the maximum daily variation between the highest and lowest hourly consumption levels is in the range of 125% to 164%. However, using the ratio of a customer's maximum to minimum consumption level may not be a good proxy of the ratio of a customer's maximum to minimum demand reduction capability because such an approach makes the implicit assumption that a customer's demand reduction capability is directly proportional to its consumption level. This may not be a good assumption because higher consumption levels may be associated with disproportionally higher amounts of discretionary energy usage.

[86] *See* TS ISO Tariff § III.8.

[87] Order No. 745 at P 94.

3. Increasing the number of days of meter data needed to establish an initial Demand Response Baseline for a new demand resource from 5 days to 10 days.

10. ENERGY MARKET SETTLEMENT

Q: Please compare and contrast energy market settlement for the transitional solution and the fully integrated solution.

A: Energy market settlement in the transitional solution is very similar to settlement in the fully integrated solution. In both the transitional and fully integrated solutions, Market Participants are paid their Day-Ahead Demand Reduction Obligation multiplied by the Day-Ahead LMP.[88] The Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts scheduled by the ISO in the Day-Ahead Energy Market multiplied by one plus the percent average avoided peak distribution losses[89]. Also in both the transitional and fully integrated solutions, Market Participants are paid or charged for the difference between their Real-Time Demand Reduction Obligation and their Day-Ahead Demand Reduction Obligation multiplied by the Real-Time LMP.[90] The payment for the amount by which the Real-Time Demand Reduction Obligation exceeds the Day-Ahead Demand Reduction Obligation in an hour is set to zero if the Real-Time LMP for that hour is less than the Demand Reduction Threshold Price to recognize the payment restrictions imposed by the Commission's consumer net benefits test.[91]

The primary difference in energy market settlement between the transitional and fully integrated solutions, as noted above, is that the transitional solution has no NCPC provisions. NCPC credits and charges are only applied to resources and

[88] *See* TS Appendix E at § 9.1.

[89] *See* TS ISO Tariff at § I.2.2.

[90] *See* TS Appendix E at § 9.2.1.

[91] *Id.*

demands that are integrated in the energy markets. The transitional solution does not integrate demand resources into the energy markets. Therefore, NCPC cannot be credited or charged until these resources are integrated into the energy markets, which will occur at the time the ISO implements its fully integrated solution.

11. COST ALLOCATION

Q: How does the ISO propose to allocate costs associated with demand resources participating in the transitional solution?

A: The allocation of demand response costs in the transitional solution will be the same as in the fully integrated solution. The ISO proposes that charges or payments resulting from real-time demand reductions produced by Real-Time Demand Response Assets be allocated on an hourly basis proportionally to Real-Time Load Obligation on a system-wide basis, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Dispatchable Asset Related Demand postured by the ISO.[92]

[92] *See* TS Appendix E at § 9.3.

IV. CONCLUSION

Q: Do you wish to make any concluding remarks?

A: Yes. To summarize, the proposed tariff provisions comply with Order No. 745 because they include the following elements as required by the Commission:

- The required demand response compensation approach;[93]
- A monthly determination of the conditions under which it is cost-effective to pay demand resources for reductions in energy consumption;[94]
- The required demand response cost allocation mechanism;[95] and
- Modifications to improve the accuracy of Demand Response Baselines.[96]

Additionally, this filing includes the following items as required by the Commission:

- A description of the methodology, the analysis, associated data and the actual supply curves used to determine the monthly Demand Reduction Threshold Prices for the last 12 months, which will be used to implement the Commission's consumer net benefits test.[97]
- An explanation of how the ISO's measurement and verification protocols will ensure that appropriate Demand Response Baselines are set, and that demand response will continue to be adequately measured and verified to ensure performance of each resource.[98]

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[93] Order No. 745 at PP 47, 48.

[94] Order No. 745 at PP 4, 78, 94.

[95] Order No. 745 at P 102.

[96] Order No. 745 at P 94.

[97] Order No. 745 at PP 79, 80.

[98] Order No. 745 at P 94.

Accordingly, the ISO's filing is fully compliant with Order No. 745 and the proposed tariff provisions are appropriate.

Q: Does this conclude your testimony?

A: Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 8/18/11

Henry Y. Yoshimura

Exhibit A to Attachment 5

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Development of Demand Response Price Thresholds

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CRA Project No. D16558/D16559

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Table of Contents

1. Executive Summary

On March 15, 2011, the Federal Energy Regulatory Commission ("Commission") issued its final rule on demand response compensation in Docket No. RM10-17-000 (Order No. 745, or the "Order").[1] Among other things, the Order requires ISOs/RTOs that have "a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals" to pay demand response resources the full locational marginal price (LMP) when these resources have the capability to balance supply and demand and when payment is cost-effective as determined by a net benefits test accepted by the Commission.

The Order anticipated ensuring that demand response is cost effective through the use of a net benefits test that is satisfied when the overall reduction in customer energy payments from reduced LMPs exceeds the cost of paying demand-response providers. The net benefits test, as provided in the Order, can be implemented by establishing a price threshold, updated on a monthly basis, at which the dispatch of demand-response resources will be cost-effective, and the Order directs each ISO/RTO to "develop a mechanism as an approximation to determine" such a price threshold monthly.[2] Load reduction offers must then be at or above this threshold to be considered.

ISO New England ("ISO-NE") retained Charles River Associates ("CRA") to conduct the analysis used to determine monthly threshold prices; the analytic approach, associated data, and findings are documented in this report.

The principal finding of the study was the validation of a supply curve analysis with real-time generator offer data for use in determining threshold prices in New England. It was found that regression with a cubic plus exponential function approximates supply curves well, and that net benefit thresholds determined using supply curves developed in this manner correspond closely to those determined using the much more sophisticated hourly dispatch simulation. Developing smooth supply curves using non-linear regression of real-time generator offers, calculating net benefit thresholds based on those supply curves, and adjusting the thresholds using fuel price indices is a practical approach which ISO-NE can adopt for use in implementing demand response net benefit threshold prices in compliance with the Commission's Order. A number of practical considerations for implementing the approach, including fuel price volatility, year-to-year variation in load, and baseline accuracy, are addressed in this report.

1 Demand Response Compensation in Organized Wholesale Energy Markets, Final Rule, 134 FERC ¶ 61,187, Order No. 745, Docket No. RM10-17-000, March 15, 2011.

2 Order at ¶ 4.

2. Background

On March 15, 2011, the Federal Energy Regulatory Commission ("Commission") issued its final rule on demand response compensation in Docket No. RM10-17-000 (Order No. 745, or the "Order").[3] Among other things, the Order requires ISOs/RTOs that have "a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals" to pay demand response resources the full locational marginal price ("LMP") when these resources have the capability to balance supply and demand and when payment is cost-effective as determined by a net benefits test accepted by the Commission. Additionally, each ISO/RTO is directed to evaluate its current measurement and verification rules and to develop appropriate modifications, if necessary, to ensure that baselines used to quantify individual resources' demand response remain accurate.[4]

The Order anticipated ensuring that demand response is cost effective through the use of a net benefits test that is satisfied when the overall reduction in customer energy payments from reduced LMPs exceeds the cost of paying demand-response providers. The net benefits test, as provided in the Order, can be implemented by establishing a price threshold, updated on a monthly basis, at which the dispatch of demand-response resources will be cost-effective, and the Order directs each ISO/RTO to "develop a mechanism as an approximation to determine" such a price threshold monthly.[5] Load reduction offers must then be at or above this threshold to be considered.

It is obvious — and the Commission recognized — that the fixed threshold approach adopted in the Order might "result in instances both when demand response is not paid the LMP but would be cost-effective and when demand response is paid the LMP but is not cost-effective." The Commission accepted this outcome, "given the apparent computational difficulty of adopting a dynamic approach that incorporates the [cost effectiveness evaluation] in the dispatch algorithms at this time."[6]

The Order requires ISOs/RTOs to file by July 22, 2011 the analysis, associated data and the supply curves used to determine the monthly threshold prices for the last 12 months that implement the net-benefits test, and starting the month prior to the effective date, update and publish threshold prices for each month by the 15th day of the preceding month.[7] ISO New

3 Demand Response Compensation in Organized Wholesale Energy Markets, Final Rule, 134 FERC ¶ 61,187, Order No. 745, Docket No. RM10-17-000, March 15, 2011.

4 Although the term "resource" has specific meaning in the ISO New England market rules, it is used here in the generic sense.

5 Order at ¶ 4.

6 Order at ¶ 80.

7 On July 8, 2011, the Commission issued a Notice granting ISO-NE's request for an extension of time to submit its compliance filing on demand response compensation pursuant to Order No. 745 by August 19, 2011.

England ("ISO-NE") retained Charles River Associates ("CRA") to conduct the analysis; the analytic approach and findings are documented in this report.

3. The Net Benefits Test

The Commission characterizes the monthly threshold price as the "price corresponding to the point along the supply stack beyond which the overall benefit from the reduced LMP resulting from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources."[8]

The Order includes language that defines the net benefits test to be used in the determination of monthly price thresholds and prescribes an approach to determine whether load reductions from demand response resources meet the net benefits test:

> "The ISOs and RTOs are to select a representative supply curve for the study month, smooth the supply curve using numerical methods, and find the price/quantity pair above which a one megawatt reduction in quantity that is paid LMP would result in a larger percentage decrease in price than the corresponding percentage decrease in quantity (billing units). Beyond that point, a reduction in quantity everywhere along an upward sloping supply curve would be cost-effective."[9]
>
> and
>
> "… the test is to determine where: (Delta LMP x MWh consumed) > (LMPNEW x DR); where LMPNEW is the market clearing price after demand response (DR) is dispatched and Delta LMP is the price before DR is dispatched minus the market clearing price after DR is dispatched."[10]
>
> and
>
> "… the threshold point along the supply stack for each month will fall in the area where the supply curve becomes inelastic, rather than the extreme steep portion at the peak or in the flat portion of the supply curve."[11]

The approach can be illustrated using an idealized supply curve, as in Figure 1. In this simplistic example, customer energy payments are the product of the LMP and the load, and payments to demand response providers for a quantity of demand response ΔL are the product of ΔL and the resulting change in price, $P_1 – P_2$, represented by area *B* in the figure. The resulting reduction in customer energy payments is then the area *A*, or $(P_1 – P_2) \times L$.

The point at which the reduction in customer energy payments equals the payments to demand response providers, i.e., the point of zero net benefits, is where the areas A and B are equal. This is also the point on the supply curve where the price elasticity of supply is equal to one, i.e., the point above which the percent change in the quantity supplied as one moves slightly up or slightly down the curve is less than the percent change in price. At the net benefit threshold price, the derivative (local slope) of the supply curve is equal to the

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8 Order at ¶ 4.

9 Order at fn 161.

10 Order at fn 162.

11 Order at ¶ 80.

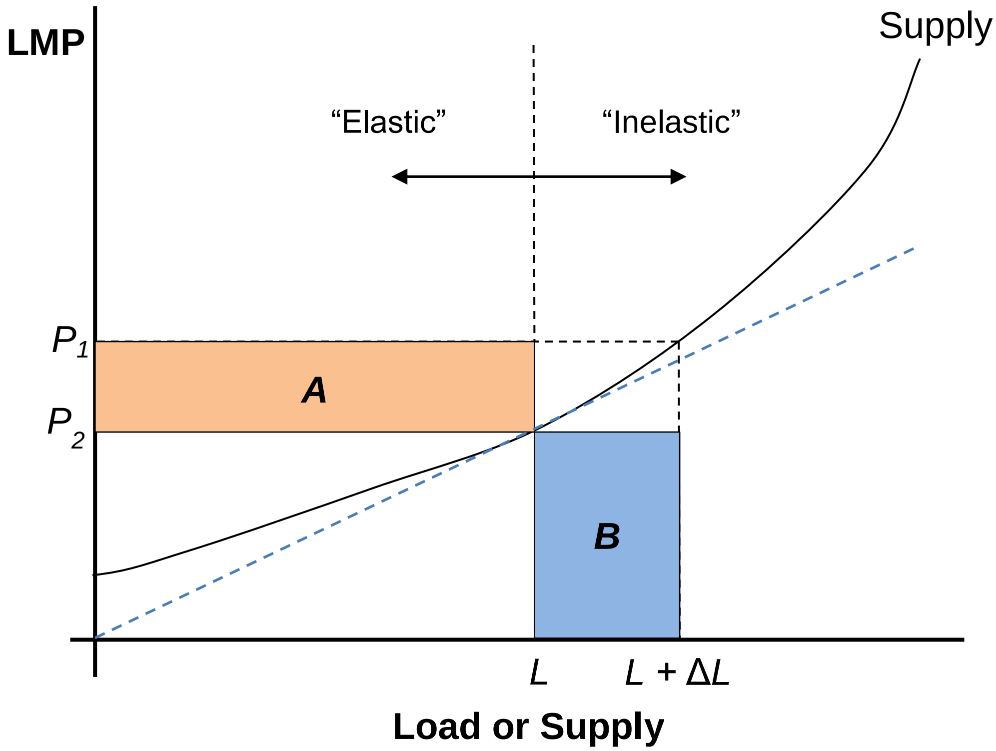

Figure 1. Idealized electricity supply curve, illustrating demand response net benefit threshold price P_2.

slope of a line passing between that point on the curve and the origin, as illustrated in the figure.

In practice, a real electricity supply curve consists of a staircase of flat increments for each block of a generating unit or group of blocks with the same offer price, so it is necessary to fit a smooth curve to the portion of interest in order to apply the net benefit test, because each flat segment is locally elastic (slope = 0).

The method outlined above ignores numerous complicating factors such as congestion, revenue overcollection due to marginal losses, imports and exports, pumped storage, outages, startup costs, generator operating constraints (e.g., minimum generation level), unit commitment, and load. Do these factors affect the relationship between payments to demand response providers and reduction in customer energy payments so much as to make calculation of the net benefit threshold using the supply curve approach not accurate enough for practical use? The answer probably depends on the specific characteristics of the power system to which the method is applied. For example, the method might not yield very accurate results for a system in which congestion has a dominant effect, depending on the location of the demand response.

To determine whether the supply curve approach is accurate enough for use in the New England electricity system, ISO-NE engaged CRA to test the method and compare its results to those of a more sophisticated analysis using an hourly security-constrained dispatch model

(GE MAPS), and based on the results of the analysis, develop a method for determining net benefit thresholds in practice, in compliance with the Commission's Order.

Using the more sophisticated hourly dispatch approach, it is possible to simulate a power system and electricity market for each hour of a month or a year and to compare over the period the total energy payments by customers to the total payments to demand response providers. Under that approach, the calculations can be done as follows.

Consider a system in which we have two groups of load: load L, and an incremental load corresponding to the quantity of demand response provided if the incremental load were interrupted (as in Figure 1).

An hourly revenue balance on the system can be represented as follows:

$$LMP_L \times \ L + \Delta L_{DR} \ - CR - MLO - OC = LMP_{Gen} \times Gen + ImpCost - ExpRev \qquad (1)$$

where

L = observed load, measured at load zones (MWh)
ΔL_{DR} = incremental load, corresponding to quantity of potential demand response (MWh)
CR = congestion rent ($)
MLO = marginal losses over-collection ($)
OC = ancillary services and uplift costs paid to generators ($)
LMP = LMP at load or generator location ($)
Gen = energy generated, measured at generator buses (MWh)
$LMP_{Gen} \times Gen$ = $GenRev$ = generator revenue ($)
$ImpCost$ = cost of energy imported to the system ($)
$ExpRev$ = revenue from energy exported from the system ($)

The net cost to serve load L (i.e., customer energy payments) is then

$$\begin{aligned} NetLoadCost &= LMP_L \times L - CR - MLO - OC \\ &= GenRev + ImpCost - ExpRev - LMP_L \times \Delta L_{DR} \end{aligned} \qquad (2)$$

Assume the load in state 1 is what would have been observed including the load associated with ΔL_{DR} and state 2 is without the load ΔL_{DR}. In other words, the load L is present in both states, $\Delta L_{DR} > 0$ in state 1, and $\Delta L_{DR} = 0$ in state 2.

The benefit calculation, consistent with the Commission's definition, is as follows:

$LoadBenefit$ = decrease in $NetLoadCost$ for load L from state 1 to state 2

In state 1,

$$\begin{aligned} NetLoadCost &= LMP_1 \times L - CR_1 - MLO_1 - OC_1 \\ &= GenRev_1 + ImpCost_1 - ExpRev_1 - LMP_1 \times \Delta L_{DR} \end{aligned} \qquad (3)$$

In state 2 (ΔL_{DR}=0)

$$NetLoadCost = LMP_2 \times L - CR_2 - MLO_2 - OC_2 \\ = GenRev_2 + ImpCost_2 - ExpRev_2 \quad (4)$$

Then,

$$LoadBenefit = \\ GenRev_1 - GenRev_2 + (ImpCost_1 - ImpCost_2) - ExpRev_1 - ExpRev_2 - \mathrm{LMP}_1 \times \Delta\mathrm{L}_{\mathrm{DR}} \quad (5)$$

$$LoadBenefit = \Delta GenRev_{1-2} + \Delta ImpCost_{1-2} - \Delta ExpRev_{1-2} - LMP_1 \times \Delta L_{DR} \quad (6)$$

To get the net load benefit, we subtract the cost that load L must pay for demand response, which is $LMP_2 \times \Delta L_{DR}$

$$NetLoadBenefit \\ = \Delta GenRev_{1-2} + \Delta ImpCost_{1-2} - \Delta ExpRev_{1-2} - LMP_1 \times \Delta L_{DR} - LMP_2 \times \Delta L_{DR} \\ = \Delta GenRev_{1-2} + \Delta ImpCost_{1-2} - \Delta ExpRev_{1-2} - (LMP_1 + LMP_2) \times \Delta L_{DR} \quad (7)$$

When $LoadBenefit$ exceeds the payment to demand response, $NetLoadBenefit$ will be greater than zero, and the demand response will be considered cost-effective:

$$\Delta GenRev_{1-2} + \Delta ImpCost_{1-2} - \Delta ExpRev_{1-2} - LMP_1 \times \Delta L_{DR} > LMP_2 \times \Delta L_{DR} \quad (8)$$

The value of $NetLoadBenefit$ can be calculated by applying equation (7) to the results of an hourly simulation for any given quantity of demand response and price threshold at which the demand response is dispatched.

4. Study objectives and analytical approach

The overarching objective of the study was to develop a method that could be used by ISO-NE staff to determine, each month, a threshold price at which load reductions from demand response resources result in net benefits to consumers. This was to be done using the following approach:

- Calculate monthly net benefit thresholds using an hourly security-constrained dispatch model (GE MAPS) for 2010
- Calculate monthly net benefit thresholds using a smoothed supply curve approach based on the supply quantity, heat rate, and price assumptions used in the hourly dispatch analysis
- Compare results from these two methods
- If the results of the hourly dispatch analysis validate the results of the unconstrained supply curve analysis, apply the unconstrained supply curve approach to real-time supply offer data for 2010 to calculate monthly net benefit price thresholds
- Additionally, evaluate whether the resulting price thresholds may adversely impact baseline accuracy by permitting very frequent load reductions if demand reduction offers are made at the price threshold

5. Analysis and findings

5.1. Hourly dispatch analysis using GE MAPS

To improve convergence in the simulations, it made practical sense to test candidate net benefit thresholds in terms of implied heat rate rather than LMP, given fuel price volatility especially in the winter months (see Figure 2).[12] We then set out to accomplish the hourly dispatch analysis as follows:

- Calibrate a GE MAPS "base case" to 2010 real-time prices, using actual zonal loads, generator outages, and weekly fuel prices
- Using 500 GE MAPS runs (100 runs for each of the five demand response quantities tested), find heat rate thresholds (and corresponding LMPs) yielding net benefit maxima for each month and demand response quantity
- Test the sensitivity of the results over a range of demand response quantities
- For each month and demand response quantity, construct a curve of net benefits as a function of heat rate threshold

[12] Throughout this report, implied heat rates are given in units of BTU/kWh. The heat rate implied by a given LMP in $/MWh is calculated as 1000 times the ratio of the LMP to the appropriate gas price in $/MMBTU, with the result in BTU/kWh.

To do this, we performed the GE MAPS runs with demand response for the following ranges of heat rate thresholds and demand response quantities:

- Heat rate thresholds: 100 to 27,700 BTU/kWh, in increments of 300 BTU/kWh
- Demand response quantities of 300, 500, 750, 1000, and 1500 MW

The demand response was allocated to each of the load zones using the actual 2010 demand response asset distribution. In a given scenario, all demand response in a zone was dispatched when zonal implied heat rate was greater than or equal to the threshold heat rate for the scenario.

We began the GE MAPS analysis by calibrating a 2010 Base Case using historical weekly fuel prices, tie flows, significant outages, and must-run generation for the year, such that the resulting zonal LMPs were consistent with historical real-time zonal LMPs for the period.

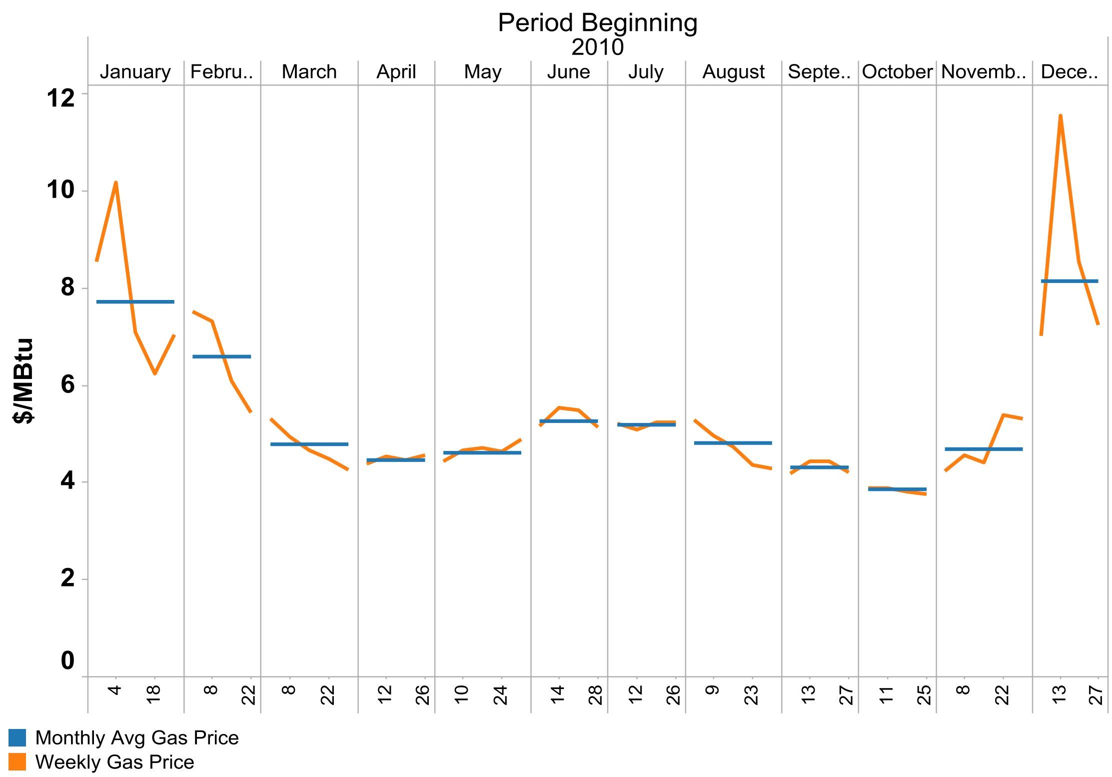

Figure 2. Historical natural gas prices used in analysis.

Figure 3 shows the net benefit results of the analysis for the 100 scenarios with 500 MW of demand response. The curve for each month is constructed by plotting the net benefits calculated using equation (7) for each of the 100 scenarios with 500 MW of demand response, over the range of heat rate thresholds. For example, the scenario using 500 MW of demand response and a threshold of 10,000 BTU/kWh shows a net benefit of roughly $90 million for July 2010. It is evident for all months that, as the heat rate threshold is decreased beginning with a high threshold, the savings increase relative to the cost (i.e., the decrease in the cost of energy is greater than the increase in payments to demand response providers). At some point, however, the savings relative to costs start decreasing as heat rate thresholds decline. The heat rate at which this change occurs is approximately (i.e., within the 300 BTU/kWh resolution of the analysis) the point of zero net benefits.

To illustrate this point, let us again consider the month of July in the 500 MW set of scenarios. At a threshold of 8,500 BTU/kWh, we observe a net benefit of about $96.7 million for July. Decreasing the threshold to 8,200 BTU/kWh causes 500 MW of demand response to be dispatched in more hours. This reduces the total net benefits for the month to about $95.5 million, indicating that the incremental demand response between 8,200 and 8,500 BTU/kWh has a negative net benefit, because the additional savings is less than the additional cost. As we increase the threshold above 8,500 — to say, 8,800 BTU/kWh — the overall cost effectiveness of the demand response dispatched at and above the 8,800 level does not change. Any positive net benefit for the demand response that would occur when the implied heat rate is at or greater than 8,500 but less than 8,800 BTU/kWh, however, would be lost if the threshold were set at 8,800 BTU/kWh. The threshold of 8,500 BTU/kWh is therefore the net benefit threshold for July 2010, given a demand response quantity of 500 MW; the net benefit thresholds for all of the scenarios can be taken as the maxima of the net benefits vs. heat rate curves.

The net benefit curves display additional characteristics worth noting. For each month, there is a heat rate threshold below which the net benefits are constant. At those thresholds, demand response is dispatched in every hour, so reducing the threshold further has no impact. This point occurs around 5,500 BTU/kWh for July. Likewise, for each month there is a heat rate threshold above which raising the threshold has no or very little impact on net benefits. For example, for November, this is around 14,000 BTU/kWh. There are very few hours with implied heat rates above 14,000 BTU/kWh in November, so increasing the threshold has little impact.

Figure 4 shows very similar results for the case in which 1500 MW of demand response is dispatched; results for the remaining scenarios are included in Appendix A. The net benefit threshold heat rates are translated into threshold LMPs using monthly average natural gas prices, and the results for all scenarios are shown in Table 1 and Table 2.

One of the principal findings of the hourly dispatch analysis was that the results were robust. That is, the net benefit threshold heat rate is relatively consistent across months, ranging from 8,200 to 8,800 BTU/kWh, and is relatively insensitive to demand response quantity. The corresponding LMPs vary more widely due to gas price volatility, and were found to be in the range of $33 to $69/MWh.

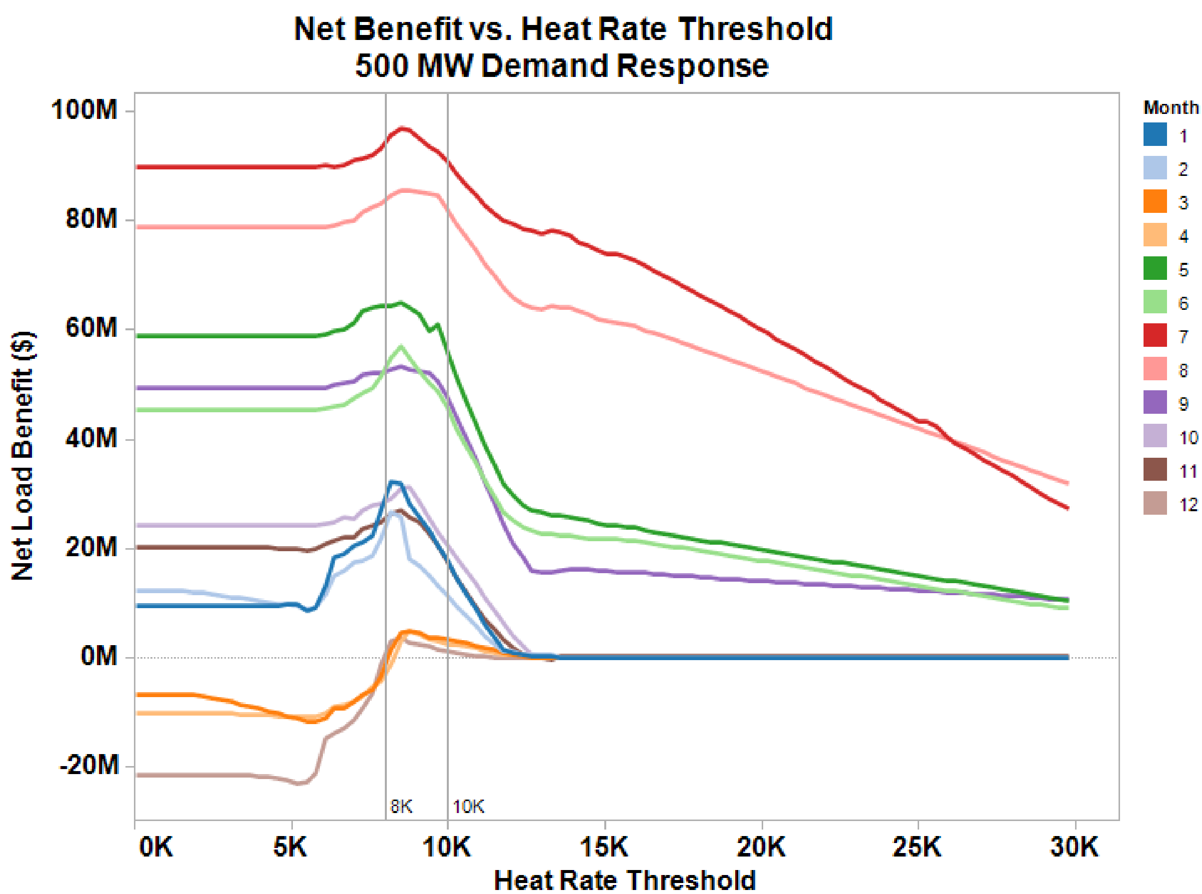

Figure 3. Results of 100 GE MAPS runs with 500 MW of demand response, showing net benefit as a function of heat rate threshold for each month of 2010.

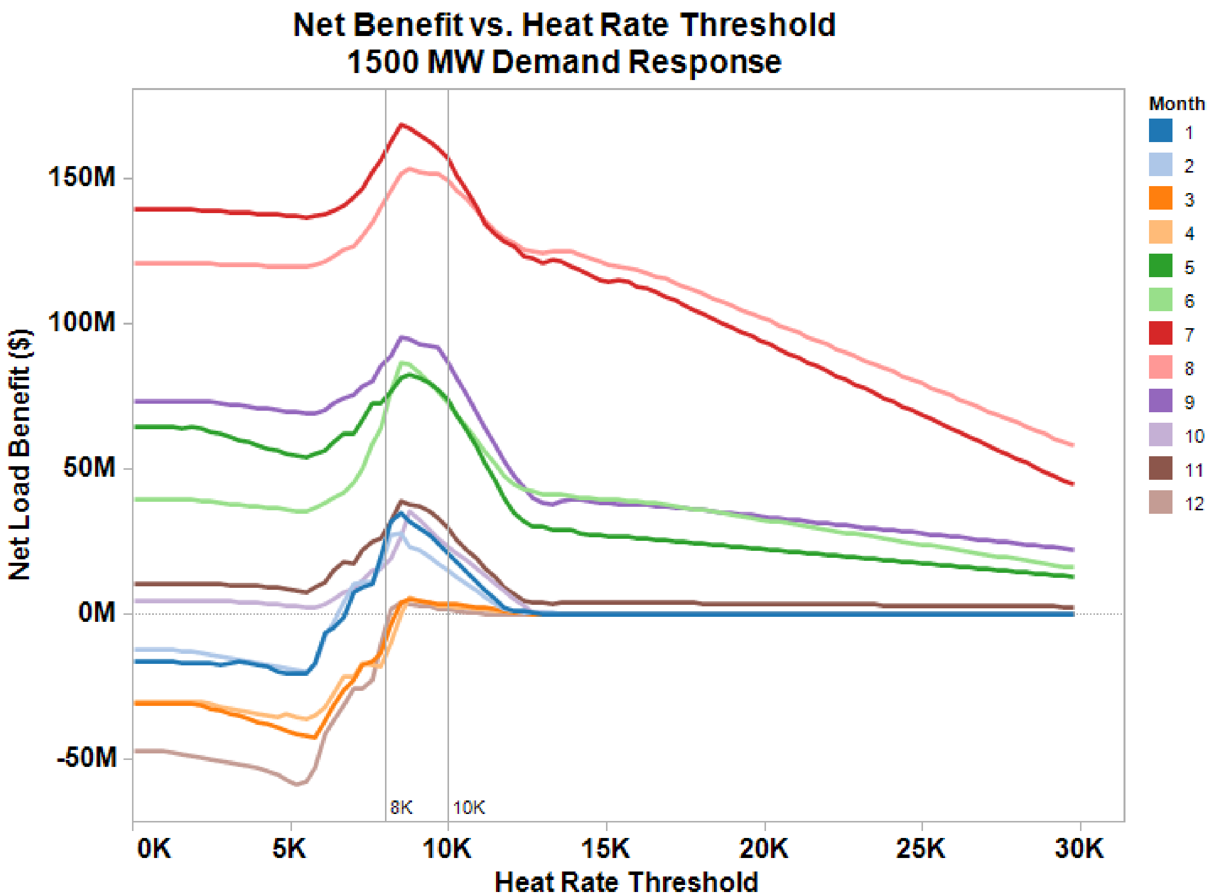

Figure 4. Results of 100 GE MAPS runs with 1500 MW of demand response, showing net benefit as a function of heat rate threshold for each month of 2010.

Table 1. Net Benefit Threshold Heat Rates for Hourly Dispatch Analysis

DR Quantity (MW)	300	500	750	1000	1500
Month	**Threshold Heat Rate (BTU/kWh)**				
1	8,200	8,200	8,500	8,500	8,500
2	8,200	8,200	8,200	8,200	8,500
3	8,800	8,800	8,800	8,800	8,800
4	8,800	8,800	8,800	8,800	8,800
5	8,500	8,500	8,500	8,500	8,800
6	8,500	8,500	8,500	8,500	8,500
7	8,500	8,500	8,500	8,500	8,500
8	8,500	8,800	8,800	8,800	8,800
9	8,500	8,500	8,500	8,500	8,500
10	8,500	8,800	8,800	8,800	8,800
11	8,500	8,500	8,500	8,500	8,500
12	8,500	8,500	8,500	8,500	8,500

Table 2. Net Benefit Threshold LMPs for Hourly Dispatch Analysis

DR Quantity (MW)	300	500	750	1000	1500
Month	**Threshold LMP ($/MWh)**				
1	$63.2	$63.2	$65.6	$65.6	$65.6
2	$53.9	$53.9	$53.9	$53.9	$55.9
3	$42.0	$42.0	$42.0	$42.0	$42.0
4	$39.1	$39.1	$39.1	$39.1	$39.1
5	$39.1	$39.1	$39.1	$39.1	$40.5
6	$44.7	$44.7	$44.7	$44.7	$44.7
7	$44.0	$44.0	$44.0	$44.0	$44.0
8	$40.8	$42.3	$42.3	$42.3	$42.3
9	$36.6	$36.6	$36.6	$36.6	$36.6
10	$32.8	$33.9	$33.9	$33.9	$33.9
11	$39.8	$39.8	$39.8	$39.8	$39.8
12	$69.2	$69.2	$69.2	$69.2	$69.2

5.2. Analysis of supply curves constructed from simulation inputs

The net benefit test using supply curve analysis is outlined at a high level in Section 3. In this section the analysis and findings based on supply curves constructed from the simulation inputs are described in detail.

The generating plant input assumptions used in the hourly dispatch analysis, including capacity, generator heat rates, variable operating and maintenance costs, emissions costs, and fuel prices, were used to construct supply curves for each month.[13] For the purposes of the supply curve analysis, the supply stack excluded imported power offerings and pumped storage generation, and ignored outages. Each unit was treated as a single block, using the full load heat rate, since one cannot easily capture the dynamics of startup cost, minimum generation levels and unit commitment in a simple supply stack. Despite these shortcomings, the simple supply stack represents a reasonable approximation to the supply curve averaged over each month.

From each of these raw supply curves, a smoothed supply function *P*(*x*) was formed, where x is the supply in MW, and *P* is the price, using non-linear regression on an appropriately sampled portion of the raw supply curve. It was found that a function of the following form, combining a cubic component with an exponential, yielded the best fit

$$P(x) = A + Bx + Cx^2 + Dx^3 + e^{(Ex+F)} \quad (9)$$

where *P(x)* is the price in $/MWh as a function of *x,* the cumulative MW supply quantity, and *e* is the mathematical constant 2.718281828. The regression analysis yielded the best-fitting coefficients *A* through *F*. The exponential characteristic of the curve allows a reasonably good fit to the steep tail of the supply curve, where expensive and small peaking units

13 Supply curves differed from month to month inasmuch as fuel prices varied and due to seasonal changes in unit capacity (summer and winter); generating plant input assumptions were based on publicly available data.

dominate the supply stack, while the cubic characteristic allows a better fit to the broader, more gently rising portion of the curve going from large steam units to intermediate gas-fired combined cycle units. The lowest portion of the supply stack, consisting of low cost hydro, wind, nuclear, and some base load coal units, is not included in the fit, because it is clear from casual inspection that the supply stack has large elastic portions in this region of the supply curve. An example of the fit is shown in Figure 5 for June 2010, and similar figures for all months are included in Appendix A.

Once the coefficients were determined for each month, the resulting expressions represented smoothed supply curves with price P as a function of supply quantity x. The coefficients determined through this process are listed in Table 3.

A net benefit threshold for each month was then determined as the price on the curve above which an incremental quantity of supply (Δx) times the price ($P(x)$) is everywhere less than the associated incremental change in price, $\Delta P = P(x + \Delta x) - P(x)$, times the supply ($x$), as described in Section 3. For each curve, this point was found through an evaluation of the derivative at each point. The derivative of the function P in equation (9) is:

$$dP/dx = B + 2Cx + 3Dx^2 + Ee^{(Ex+F)} \tag{10}$$

where the coefficients B through F have the same values determined by regression. Finally, a net benefit threshold price was determined as the price at the highest value of x on the smoothed supply curve for which the derivative of the curve (dP/dx) is equal to (P/x), i.e.,

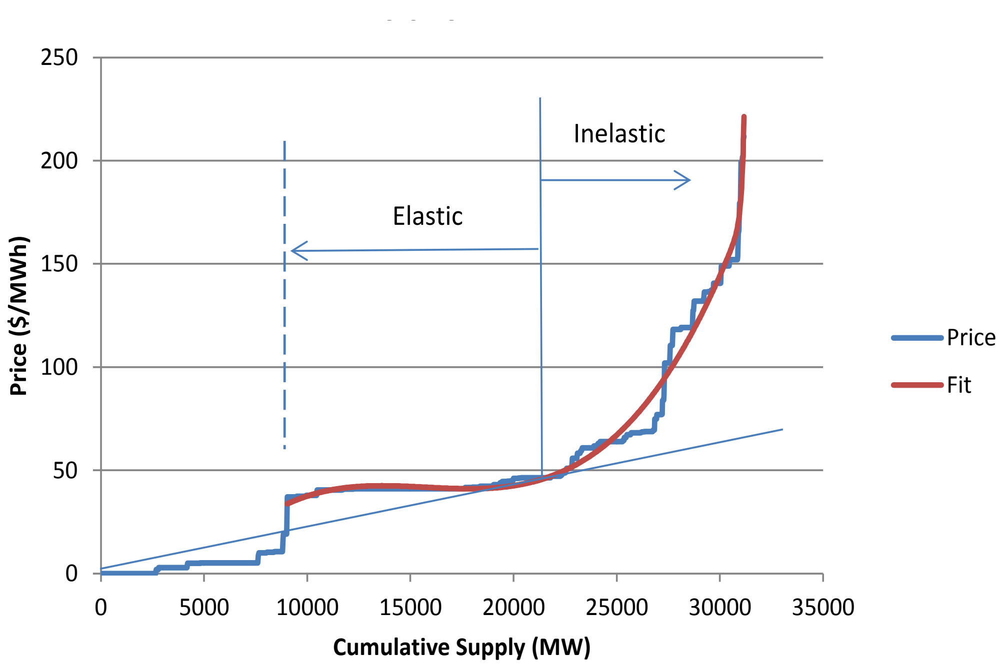

Figure 5. Smooth curve fit to raw supply curve constructed from data used in the simulations for June 2010.

where the price elasticity of supply equals one.[14] In Figure 5, the threshold can be seen at the point where the blue line through the origin is tangent to the fit curve. Note that the raw supply curve shown has many short flat portions above the threshold price (near $43.58 for June 2010, corresponding to a heat rate of 8,294 BTU/kWh).

We found that the threshold metric is sensitive to the details and granularity of the fitted curve choice: A smooth global fit will generally lead to lower threshold values than a more detailed fit with more local inflection points (bumps). The selected six-parameter expression yields a smooth curve with good overall fit to the supply curves examined, providing unambiguous thresholds at the highest elastic–to-inelastic transition points.

The resulting threshold LMPs were translated to implied heat rates using weighted average monthly natural gas prices. The threshold LMPs, ranging from $36 to $69/MWh, and corresponding heat rates, ranging from 8,250 to 9,520, are shown in Table 4. In general, they agree well with the results of the hourly dispatch analysis, indicating that the various factors not accounted for in the supply curve analysis, such as congestion, imports and exports, pumped storage, outages, startup costs, generator operating constraints, unit commitment, and load, are not significant determinants of net benefit thresholds in New England.

The thresholds were somewhat higher for one month, October (9,520, vs. 8,800 BTU/kWh from the hourly simulation). This can be explained in large part by low gas prices in that month, causing a larger relative contribution from variable operating and maintenance costs to the implied heat rate.

Table 3. Regression Coefficients for Supply Curve Used in Hourly Dispatch Analysis

Month	A	B	C	D	E	F
1	-62.70	208.98	-126.08	26.84	16.10	-47.59
2	-71.95	225.54	-140.49	29.64	22.71	-69.36
3	-11.51	-13.71	-1.33	-22.13	1.13	3.31
4	-54.00	-12.63	-19.31	-22.80	0.98	3.97
5	-191.74	437.35	-272.53	55.71	23.37	-68.59
6	-98.05	276.67	-178.97	37.89	86.42	-265.54
7	-132.30	333.77	-209.99	43.27	15.57	-45.62
8	-175.90	415.85	-262.38	54.10	27.69	-82.45
9	-187.60	420.72	-258.67	52.17	22.57	-67.40
10	-18.53	44.44	0.73	-11.22	1.84	0.26
11	5.90	26.07	2.49	-4.77	2.57	-2.93
12	-397.28	126.36	-151.94	23.95	0.34	5.77

14 The Commission in its Order specified that the test be done using a 1 MW interval. The formulation here is equivalent, as the difference between the derivative *dP/dx* (the local slope we calculated for a very small interval of the smoothed supply curve) and Delta P / Delta X when Delta X =1 MW is trivial in the context of a 30,000 MW system.

Table 4. Net Benefit Thresholds Determined through Analysis of Supply Curve Used in Hourly Dispatch Analysis

Month	Threshold Heat Rate (BTU/kWh)*	Threshold LMP ($/MWh)
1	8,830	$68.1
2	8,590	$56.5
3	8,800	$42.0
4	8,810	$39.1
5	8,480	$39.1
6	8,290	$43.6
7	8,250	$42.7
8	8,260	$39.7
9	8,680	$37.4
10	9,520	$36.7
11	8,960	$41.9
12	8,460	$68.9

* Rounded to nearest 10 BTU/kWh.

5.3. Analysis of generator offer supply curves

Having validated the unconstrained supply curve approach, we set out to apply it to actual generator offer data for 2010. This analysis was quite similar to that just described, except for assembly of the supply curves. We assembled monthly average supply stacks from daily real-time generator offers[15] by first compiling each generator offer block (i.e., each price-quantity pair offered in the real-time energy market) for each day of the month and sorting the blocks in ascending order of price. The cumulative MW quantity at each price was calculated by summing the MWs in each block up to and including that price, and dividing by the number of days in the month. The result was an average supply stack for each month. For unbiased fitting, with equal weighting for each section of the supply curve, a sampled supply curve with uniform spacing on the x-axis (MW supply) was created from the raw data by finding the price at 25 MW intervals. We then fit smooth curves of the same cubic plus exponential function of equation (9), for the $25 to $300/MWh portion of interest for each month.[16] Thresholds were then calculated using the derivatives of the curves, as in the analysis described above. Figure 6 shows the result for June 2010; Table 5 lists the regression coefficients, Table 6 lists the resulting net benefit thresholds, and Appendix A contains curves for the remaining 11 months. All of the regressions resulted in R^2 statistics above 0.98.

Except in the winter months (December through February), the resulting threshold prices and corresponding implied heat rates shown in Table 6 are in the same general vicinity as — but somewhat lower than — those determined using the simulation input data.

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15 These data are posted in masked form on the ISO-NE website at http://www.iso-ne.com/markets/hstdata/mkt_offer_bid/rt_energy/2010/index.html.

16 Initial fits to full range showed we could ignore offers above $300; the smaller range allowed closer fits and more uniform results.

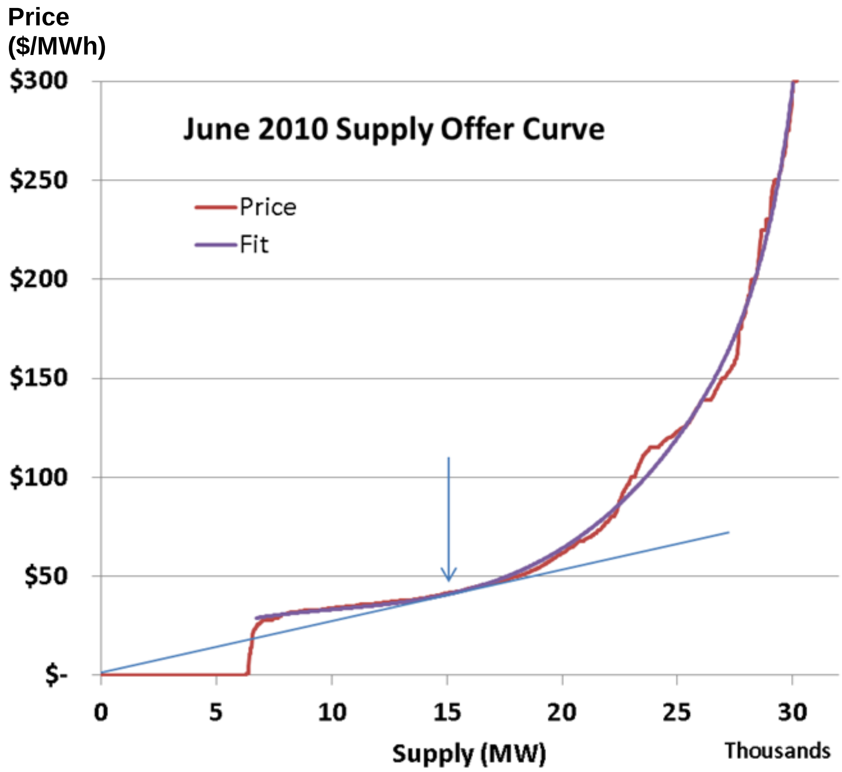

Figure 6. Average supply stack constructed from generator offers, and corresponding curve fit and net benefit threshold, for June 2010.

Thresholds for January and December, however, are in the 5,600 BTU/kWh range ($43-$45/MWh). February's threshold value is approximately 6,300 BTU/kWh ($41/MWh). In those months, relatively high natural gas prices reduce the contribution of variable operation and maintenance costs to the implied heat rate. As was the case in the analysis of supply curves derived from the data used in the hourly simulations, the heat rate implied by the October threshold is relatively high (nearly 9,000 BTU/kWh) due to the very low price of natural gas in that month.

Another observation worth noting is that in the winter months more than for others, the actual offer data (not the fitted curve) exhibit a region that is qualitatively almost straight and nearly tangent to a line to the origin, whereas raw offer data for other months show more distinctive threshold regions. As a result, the fit done slightly differently (e.g., with a different functional form) could have resulted in a threshold elsewhere along the straight region — the threshold is somewhat "fuzzy" in that sense. The January offer data, for example, form a nearly straight line from about $35 to $80/MWh (corresponding to 4,500 to 10,360 BTU/kWh at monthly average gas prices), and the December data are nearly straight from about $35 to $67/MWh (corresponding to 4,300 to 8,230 BTU/kWh). If the fit had been limited to offers from $30 - $90 (instead of from $25 to $300, used for consistency), it is likely that the resulting threshold would have been higher. Although we have not investigated the cause, it is possible that

Table 5. Regression Coefficients for Supply Curves Based on Generator Offer Data for 2010

Month	A	B	C	D	E	F
1	57.97	-81.04	75.43	-12.93	5.25	-11.02
2	63.27	-82.53	63.20	-8.49	6.12	-14.13
3	30.52	5.99	-17.37	11.19	9.96	-26.09
4	-21.66	116.30	-89.99	25.05	11.12	-29.96
5	5.47	60.95	-56.45	19.80	8.56	-21.55
6	0.63	76.16	-64.98	21.38	8.75	-21.93
7	-5.61	97.15	-88.23	28.94	13.61	-35.86
8	-22.48	134.72	-116.38	35.30	13.97	-36.69
9	20.43	-5.64	-11.05	-3.69	1.46	1.90
10	-103.83	292.08	-216.34	54.93	16.80	-55.42
11	17.78	-4.80	-9.65	-1.90	1.36	1.97
12	26.83	0.32	6.52	4.82	11.17	-30.60

Table 6. Net Benefit Thresholds Determined through Analysis of Supply Curves based on Generator Offer Data for 2010

Month	Threshold Heat Rate (BTU/kWh)*	Threshold LMP ($/MWh)
1	5,640	$43.5
2	6,270	$41.2
3	7,630	$36.5
4	8,420	$37.4
5	7,910	$36.4
6	7,900	$41.5
7	7,490	$38.8
8	7,720	$37.1
9	7,920	$34.1
10	8,990	$34.7
11	7,730	$36.1
12	5,580	$45.4

* Rounded to nearest 10 BTU/kWh.

result is an artifact of the method (fitting to prices rather than implied heat rates), combined with intra-month volatility of gas and power prices. It is possible, therefore, that using weekly or daily fuel prices to normalize offers in months with volatile fuel prices prior to fitting would eliminate the problem. Likewise, translating the resulting threshold heat rates — in months when fuel prices are volatile — to weekly or even daily threshold prices using the corresponding fuel prices would yield threshold prices that would keep pace with changing fuel prices. The other months show a more distinctive threshold region (i.e., less fuzzy) in the raw and fitted curves.

5.4. Applying net benefit thresholds in practice

Calculating and applying a net benefit threshold each month raises a number of practical considerations, discussed below.

5.4.1. Fuel price volatility

One such consideration relates to the use of thresholds determined using historical offer data, given fuel price volatility. The Commission in its Order directed each ISO/RTO to determine the price threshold monthly,[17] i.e., prior to the month in which it will be in effect, and therefore at a time when fuel prices for the effective month are not yet known. A potential result, however, is that a price threshold based on offers made during a time of low gas prices (or determined using average gas prices) would be too low for application in a period of high gas prices, potentially resulting in demand response that is not cost-effective being paid LMP.[18] The Commission recognized that fixing the threshold for an entire month and in advance of the month "may result in instances both when demand response is not paid the LMP but would be cost-effective and when demand response is paid the LMP but is not cost-effective," and stated that this outcome was acceptable given the difficulty of adopting a dynamic approach.[19] The issue of fuel price volatility can be addressed to some extent by adjusting the price threshold to account for changes in the fuel price, e.g., by multiplying the threshold for the historical month by the ratio of the current or forecast fuel price index to the corresponding value of the index for the historical month. The efficacy of such adjustments will depend on how well the forecast or current value of the fuel price index approximates actual fuel prices, and how volatile fuel prices are within the month (which is primarily a consideration during winter months, as Figure 2 shows). Using more contemporaneous fuel prices (e.g., weekly or daily) to adjust price thresholds is an option that would have obvious advantages during periods with highly volatile fuel prices. These advantages would have to be weighed against any disadvantage resulting from less advance knowledge of threshold prices.[20]

In Section 5.3, we observed that thresholds determined using offer prices in months with high fuel price volatility may be less than robust. An alternative approach, fitting smooth supply curves to historical offer data normalized by intra-month fuel prices may yield more robust thresholds, and merits further investigation.

5.4.2. Variation in load from year to year

If loads are significantly lower, e.g., in operation than in the same month of the previous year used to determine the threshold, it is possible that the threshold would be so high that it would be reached less frequently. It is also possible that higher loads in the base year would result in thresholds being exceeded more frequently in the subsequent year. We have not analyzed historical data to determine how well a threshold determined in one year performs the following year, as that was beyond the scope of this study. Nevertheless, using the same

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17 Order at ¶ 4.

18 The corollary result is demand response that is cost-effective being ineligible for payment.

19 Order at ¶ 80.

20 Such disadvantages could be offset somewhat by publishing threshold heat rates in advance, and fuel-adjusted threshold prices more frequently.

month of the previous year to determine the threshold for the effective month will mitigate such considerations to some extent.

5.4.3. Frequency of clearing and impact on baseline accuracy

Demand response resources' performance is commonly measured against baseline consumption levels. ISO-NE and others have found that when demand response resources clear for too many consecutive days, baseline accuracy can be adversely affected. To get a sense of how the number of consecutive business days with demand response would vary with threshold price levels, we analyzed 2010 real-time hourly prices to determine the maximum number of consecutive business days in a month in which a Load Zone exhibited implied heat rates at or above a range implied heat rate thresholds. The result is shown in Table 7, which shows the maximum (across Load Zones) number of consecutive business days in each month that demand response offers at the threshold price would have cleared.[21] For some of the months, the net benefit thresholds estimated from 2010 generator offer data were met or exceeded for at least one hour on *every business day* (e.g., 20, 21, or 22 days), meaning that demand response would have cleared for consecutive business days spanning several consecutive months. It is our understanding at the time of this writing that ISO-NE will address this issue by modifying the way that baselines are refreshed, and is evaluating two alternative baseline refreshment methods.

A separate analysis commissioned by ISO-NE found that a two percent median relative error was an acceptable level of baseline bias, and also that up to 13 days can be excluded from the baseline calculation before the acceptable level of bias is exceeded (the "consecutive day criterion). One of the baseline refreshment methods under consideration involves adjusting a demand response asset's baseline based on the relationships between its offer price, LMP, and a so-called Baseline Accuracy Price ("BAP").

The BAP would be determined by identifying the highest hourly real-time LMP of any Load Zone for which the number of consecutive weekdays, excluding demand response holidays, with at least one hour at or above that LMP does not exceed the consecutive day criterion, and then adjusting that LMP to account for changes in fuel prices. The consecutive day criterion would be established in advance as the maximum number of days that a demand response asset's meter data can be excluded from the computation of the asset's baseline before baseline bias exceeds a two percent median relative error. The consecutive day criterion would be determined using data from September through December of the prior calendar year.

The implied heat rates that would meet a 13-day consecutive day criterion, based on an analysis of 2010 zonal real-time prices, can be found by examining the results shown in Table 7, and are summarized in Table 8, along with the corresponding LMPs.

21 The analysis was simplistic in the sense that it ignored the impact of demand response on price, and in turn the impact on how often the demand response would clear. Consecutive day counts were reset at the start of each month, so that consecutive days at the end of one month and consecutive days at the beginning of the next would appear as two separate quantities in the table. The heat rate increments shown are the same as those used in the hourly dispatch analysis (i.e., 300 BTU/kWh).

Table 7. Number of Consecutive Business Days with Prices at or Above the Implied Heat Rate Threshold

	Heat Rate Threshold											
Month	7.0K	7.3K	7.6K	7.9K	8.2K	8.5K	8.8K	9.1K	9.4K	9.7K	10.0K	10.3K
1	17	17	17	17	17	17	14	7	7	7	7	4
2	20	20	14	14	14	12	12	12	8	8	8	7
3	23	23	23	23	23	14	14	13	13	13	13	7
4	22	22	22	22	22	22	11	11	9	9	9	5
5	20	20	20	20	20	20	20	20	20	20	20	20
6	22	22	22	22	21	21	21	21	15	11	11	11
7	21	21	21	21	21	21	21	21	21	20	20	20
8	22	22	22	22	22	22	22	16	16	16	16	16
9	21	21	21	21	21	21	21	21	21	21	21	21
10	21	21	21	21	21	21	21	21	21	21	21	21
11	20	20	20	20	20	20	20	20	20	20	18	18
12	21	17	17	12	12	12	12	12	12	12	12	11

	Heat Rate Threshold												
Month	10.6K	10.9K	11.2K	11.5K	11.8K	12.1K	12.4K	12.7K	13.0K	13.3K	13.6K	13.9K	14.2K
1	3	3	3	3	3	2	2	2	2	2	2	2	2
2	7	7	7	7	7	3	3	3	3	3	3	3	3
3	7	7	6	4	4	4	4	4	4	4	4	2	2
4	5	5	5	5	5	5	5	3	2	2	2	2	2
5	20	20	20	20	20	12	9	9	9	9	9	9	8
6	11	11	11	11	11	11	11	11	11	11	11	11	8
7	20	20	20	20	14	14	14	14	7	6	6	6	6
8	16	16	16	16	16	16	12	12	12	12	12	12	9
9	21	21	21	21	21	15	15	15	15	15	15	15	11
10	21	15	13	13	13	8	8	8	8	8	8	8	6
11	15	15	12	9	9	9	9	3	3	3	3	2	2
12	11	11	11	11	7	7	7	5	5	5	5	5	3

Table 8. LMPs Meeting 13-day Consecutive Day Criterion for 2010

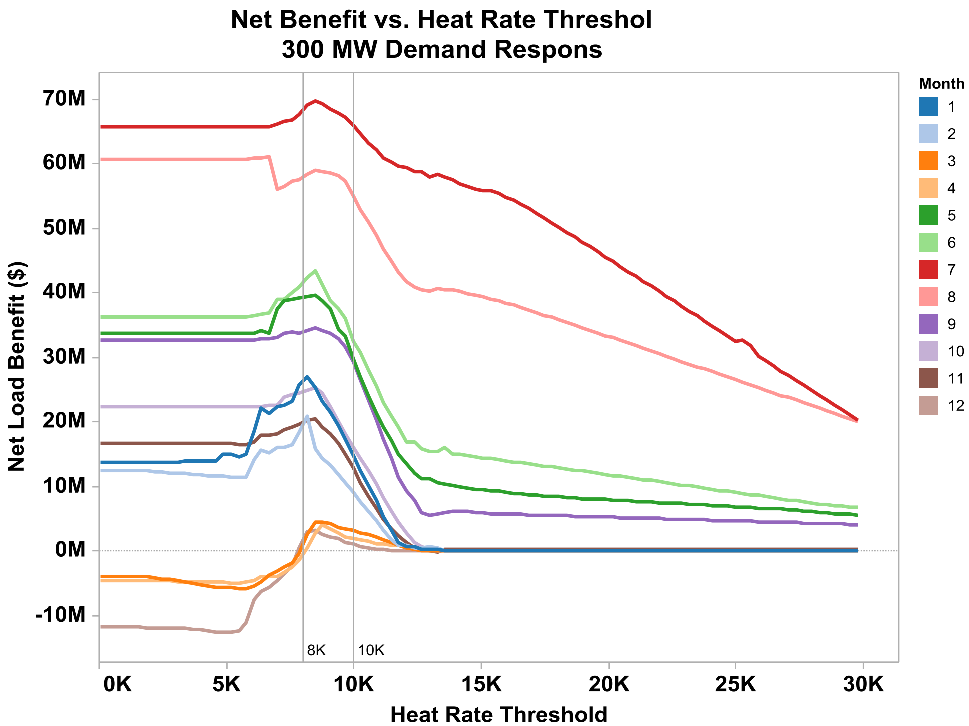
Month	Heat Rate Meeting 13-Day Criterion (BTU/kWh)*	LMP Meeting 13-day Criterion ($/MWh)
1	9,100	$ 70.2
2	8,500	$ 55.9
3	9,100	$ 43.5
4	8,800	$ 39.1
5	12,100	$ 55.7
6	9,700	$ 51.0
7	13,000	$ 67.2
8	12,400	$ 59.5
9	14,200	$ 61.2
10	11,200	$ 43.2
11	11,200	$ 52.4
12	7,900	$ 64.3

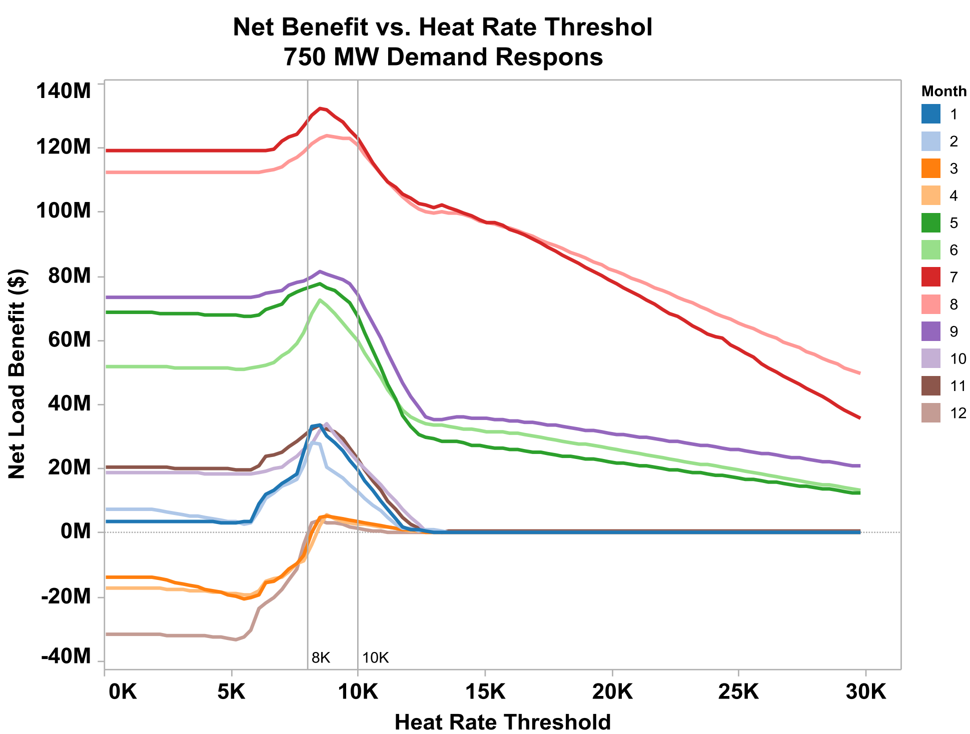
* To nearest 300 BTU/kWh.

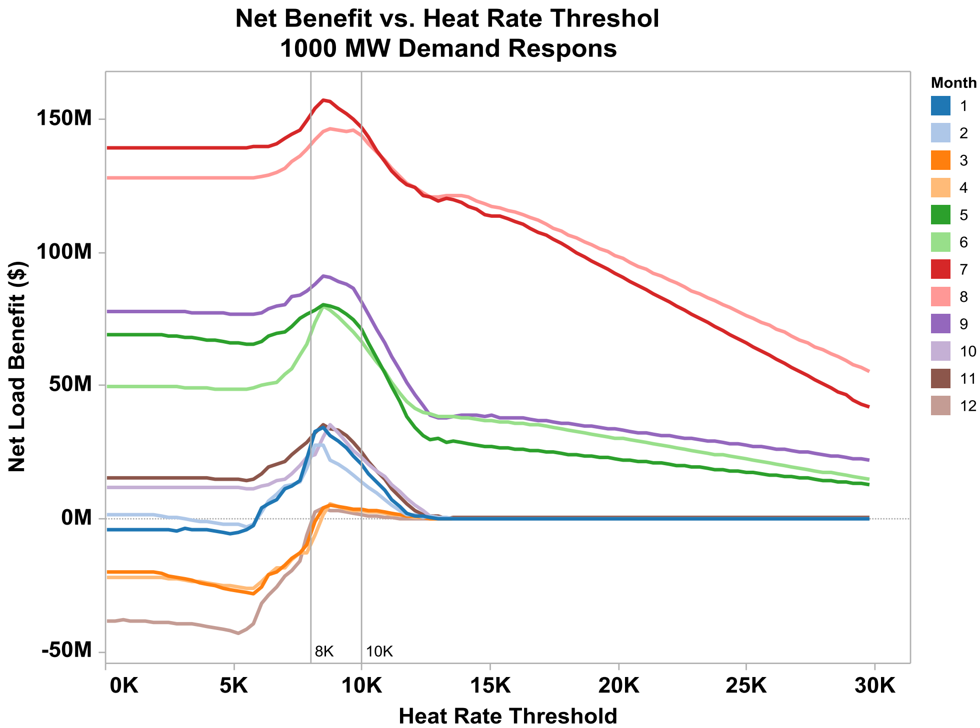
6. Conclusion

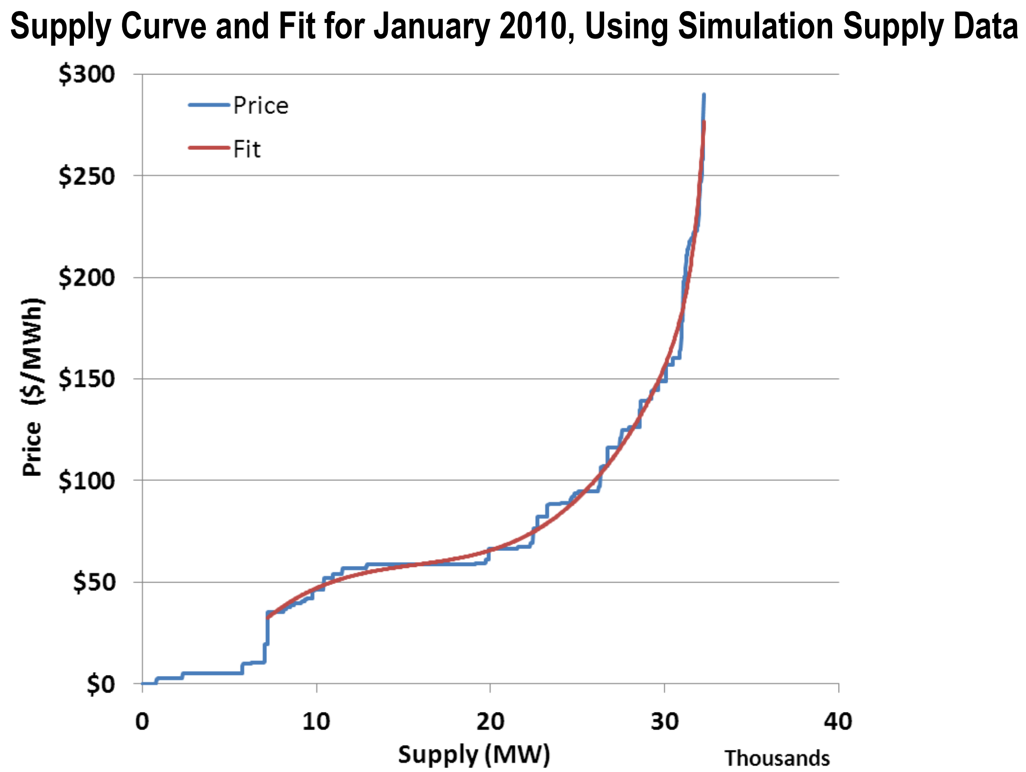
The principal finding of the study was the validation of the supply curve approach with real-time generator offer data for use in determining threshold prices. It was found that a non-linear regression performed on a sampled portion of the unsmoothed supply curve could produce a smooth curve that closely approximates the unsmoothed curve and that net benefit thresholds determined using supply curves developed in this manner correspond closely to those determined using the much more sophisticated hourly dispatch analysis. Developing smooth supply curves using a non-linear regression of real-time generator offers, calculating net benefit thresholds based on those supply curves, and adjusting the thresholds using fuel price indices is a practical approach which ISO-NE can adopt for use in establishing demand response net benefit threshold prices in compliance with the Commission's Order. A number of practical considerations for implementing the approach, including fuel price volatility, year-to-year variation in load, and baseline accuracy, are addressed in this report.

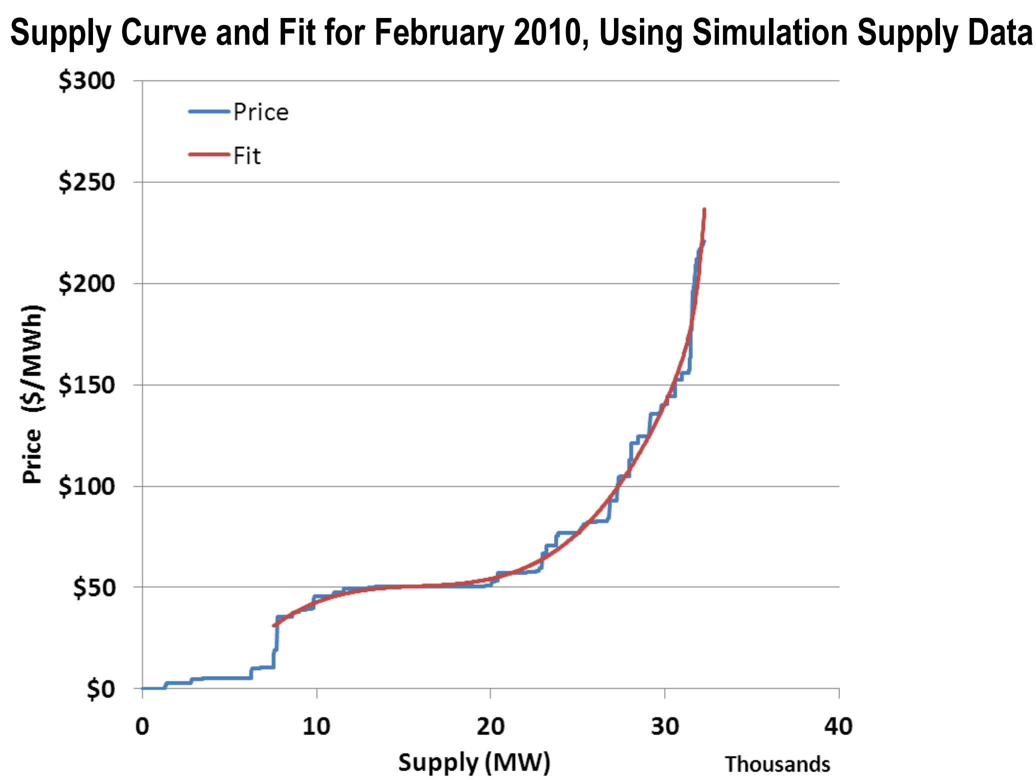
Appendix A: Additional Figures






Net Benefit vs. Heat Rate Threshol
1000 MW Demand Respons
Net Load Benefit ($)
150M
100M
50M
0M
-50M
8K
10K
0K
5K
10K
15K
20K
25K
30K
Heat Rate Threshold
Month
1
2
3
4
5
6
7
8
9
10
11
12


Supply Curve and Fit for January 2010, Using Simulation Supply Data
$300
$250
$200
$150
$100
$50
$0
Price ($/MWh)
Price
Fit
0
10
20
30
40
Supply (MW)
Thousands


Supply Curve and Fit for February 2010, Using Simulation Supply Data
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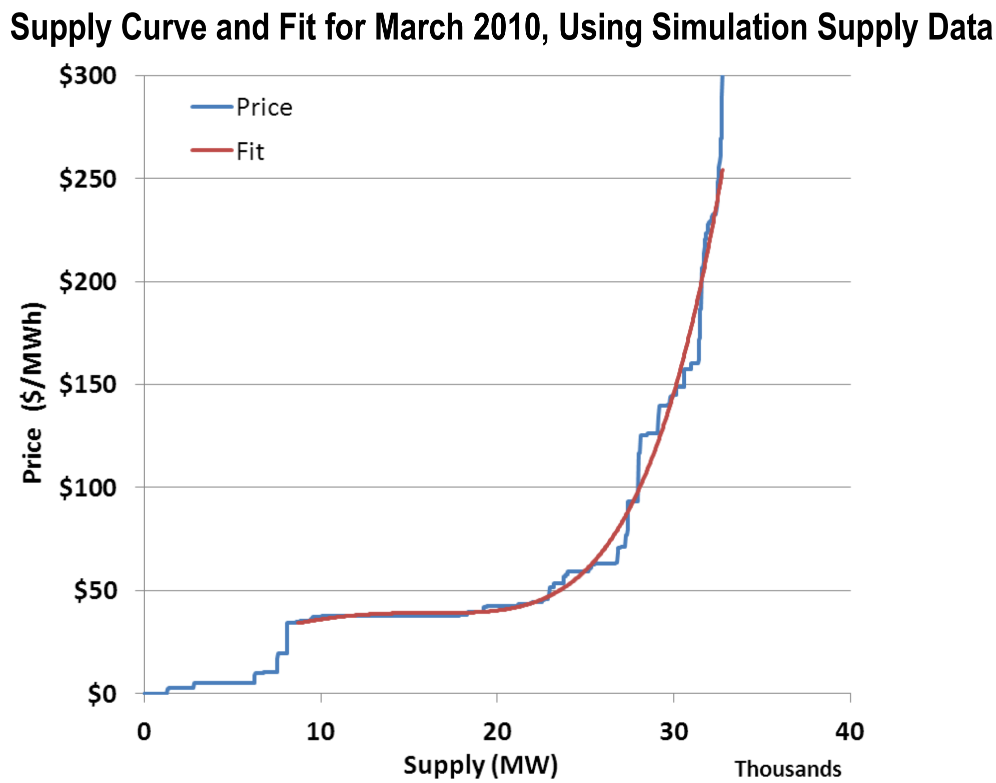
$100
$50
$0
Price ($/MWh)
Price
Fit
0
10
20
30
40
Supply (MW)
Thousands


Supply Curve and Fit for March 2010, Using Simulation Supply Data
Price
Fit
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$250
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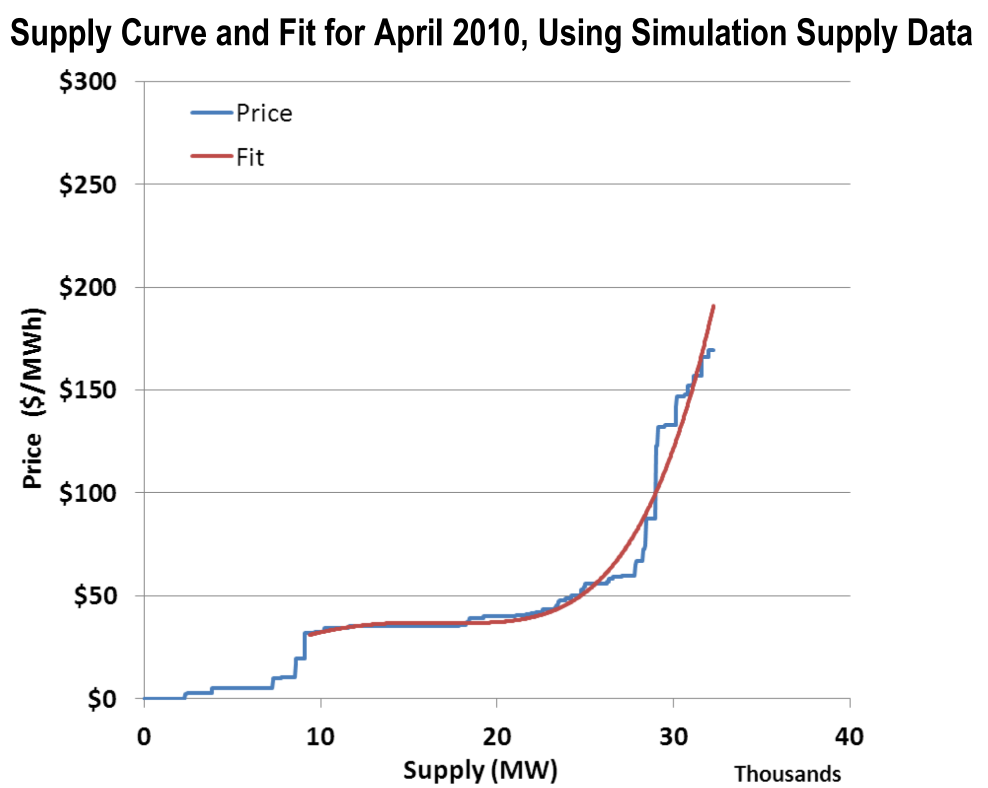
$150
$100
$50
$0
Price ($/MWh)
0
10
20
30
40
Supply (MW)
Thousands


Supply Curve and Fit for April 2010, Using Simulation Supply Data
Price
Fit
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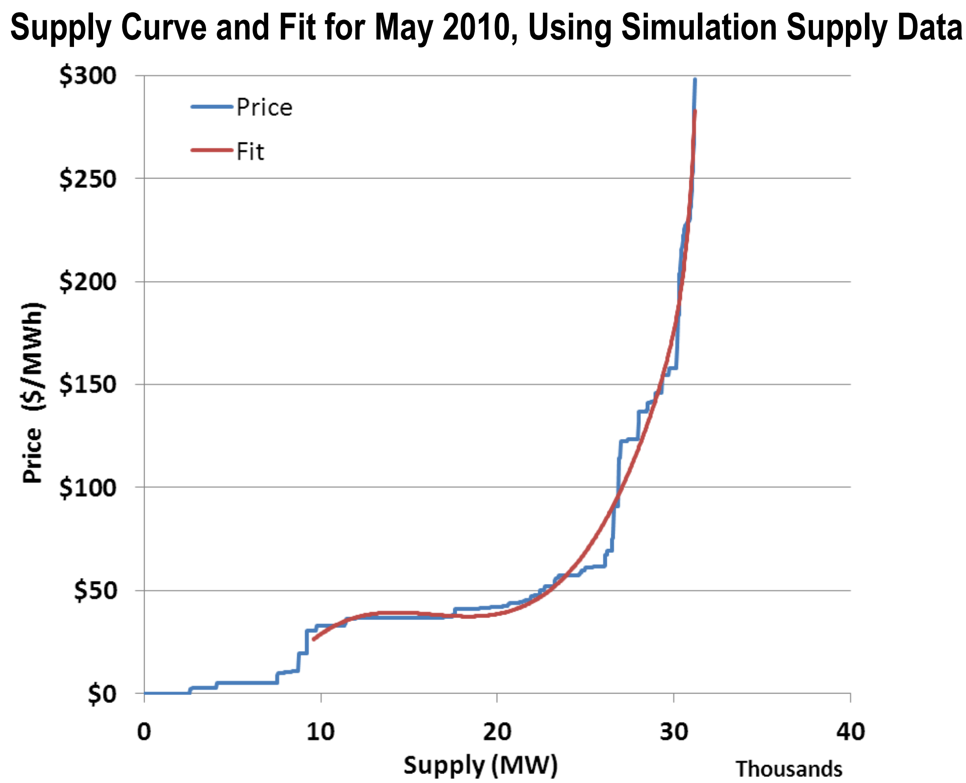
$200
$150
$100
$50
$0
Price ($/MWh)
0
10
20
30
40
Supply (MW)
Thousands


Supply Curve and Fit for May 2010, Using Simulation Supply Data
Price
Fit
Price ($/MWh)
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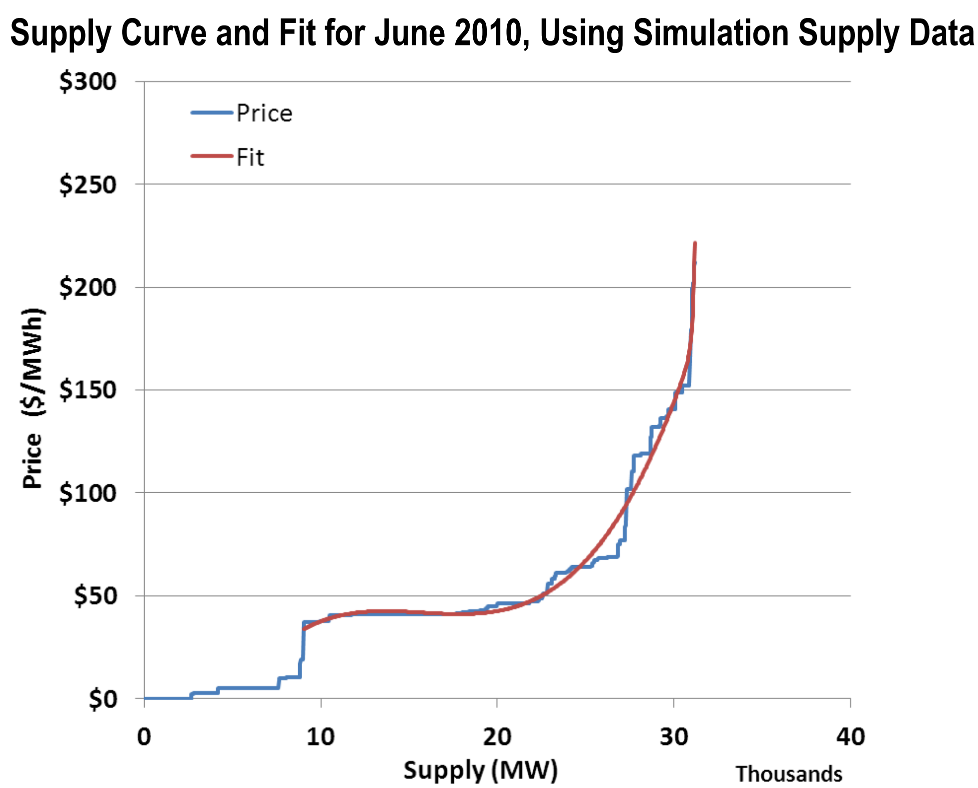
$200
$150
$100
$50
$0
0
10
20
30
40
Supply (MW)
Thousands


Supply Curve and Fit for June 2010, Using Simulation Supply Data
Price
Fit
Price ($/MWh)
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$250
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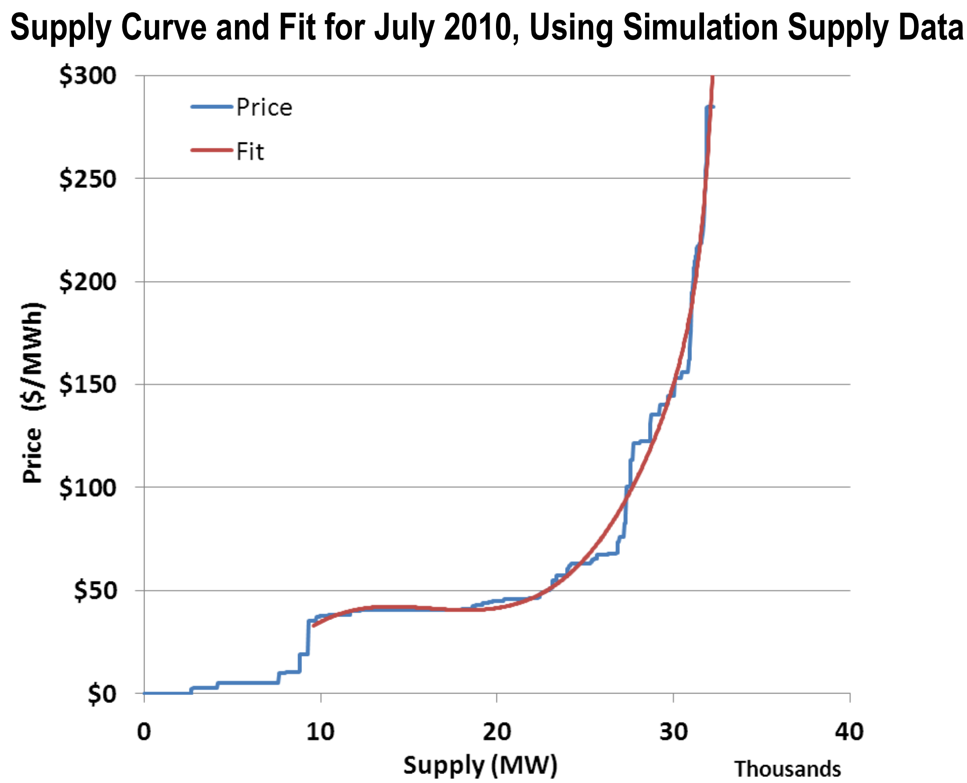
$150
$100
$50
$0
0
10
20
30
40
Supply (MW)
Thousands


Supply Curve and Fit for July 2010, Using Simulation Supply Data
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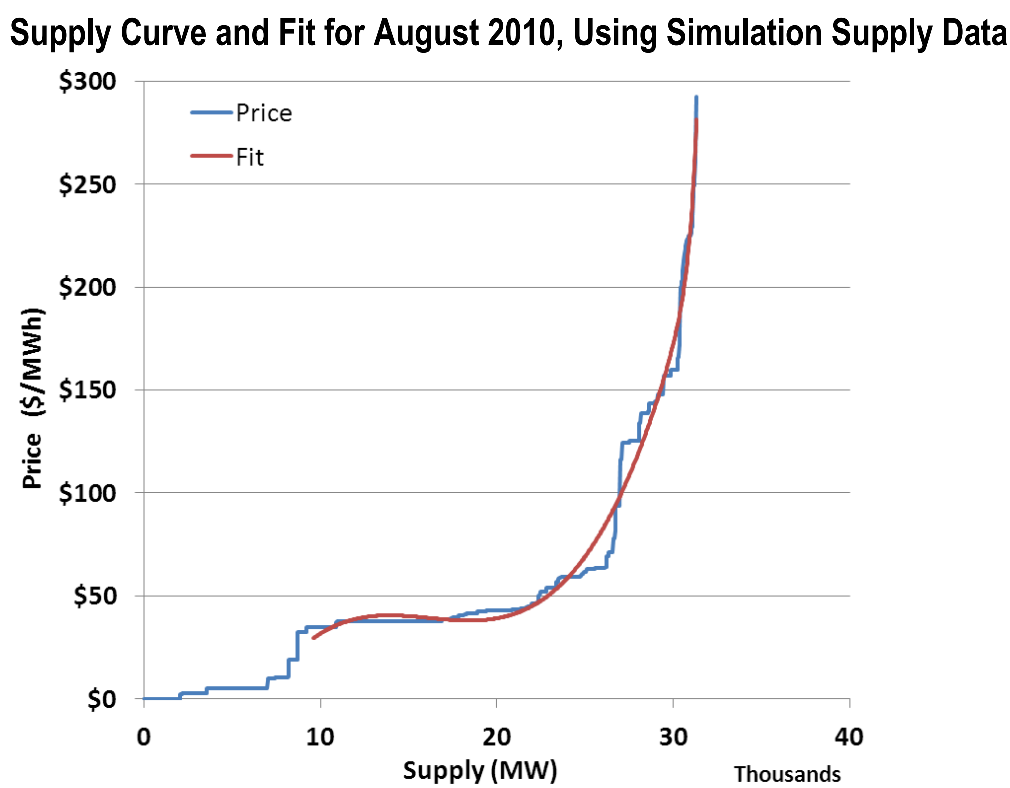
Price
Fit
Price ($/MWh)
0
10
20
30
40
Supply (MW)
Thousands


Supply Curve and Fit for August 2010, Using Simulation Supply Data
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$150
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Price
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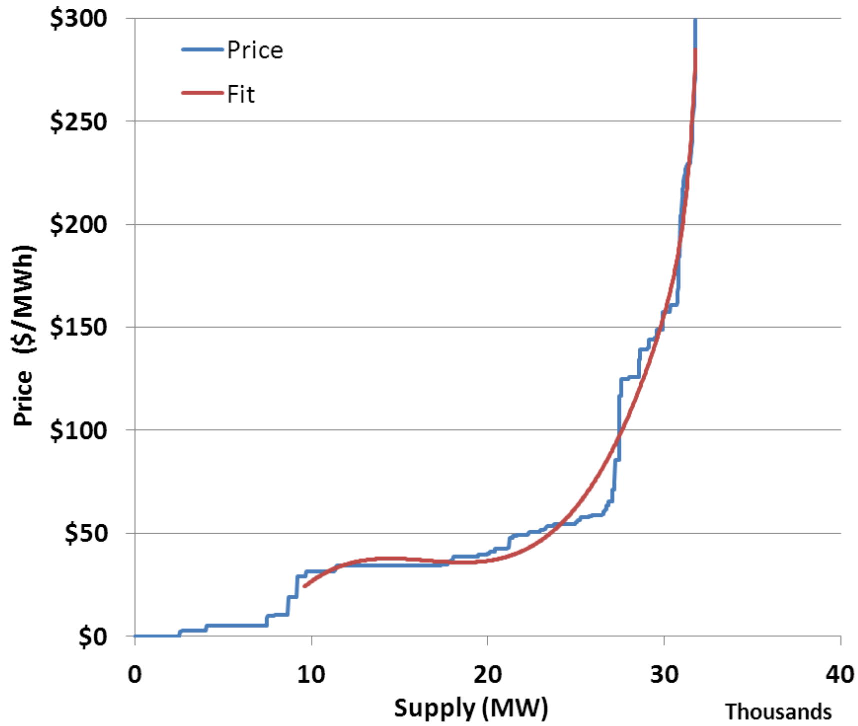
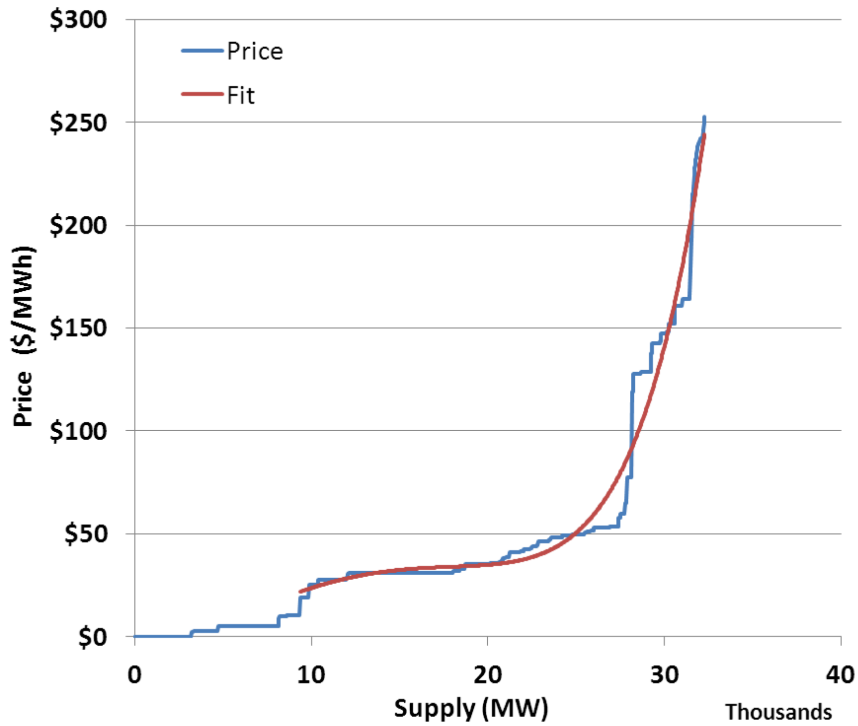
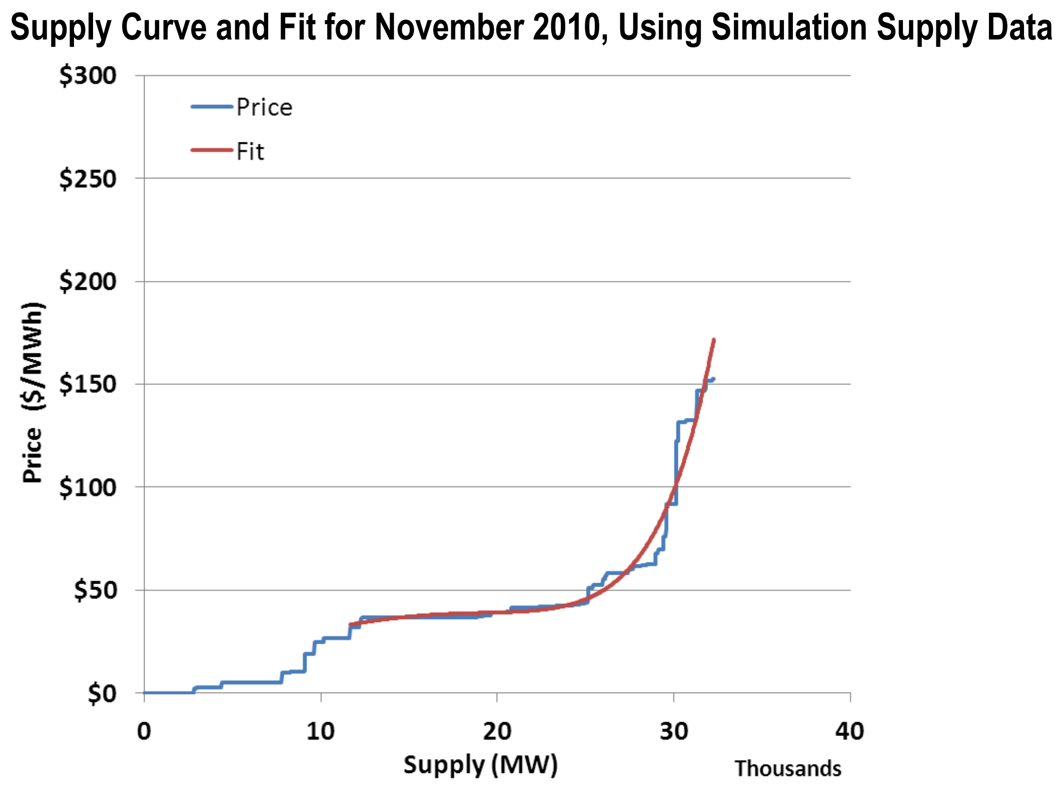
Price ($/MWh)
0
10
20
30
40
Supply (MW)
Thousands

Supply Curve and Fit for September 2010, Using Simulation Supply Data



Supply Curve and Fit for October 2010, Using Simulation Supply Data




Supply Curve and Fit for November 2010, Using Simulation Supply Data
Price
Fit
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$250
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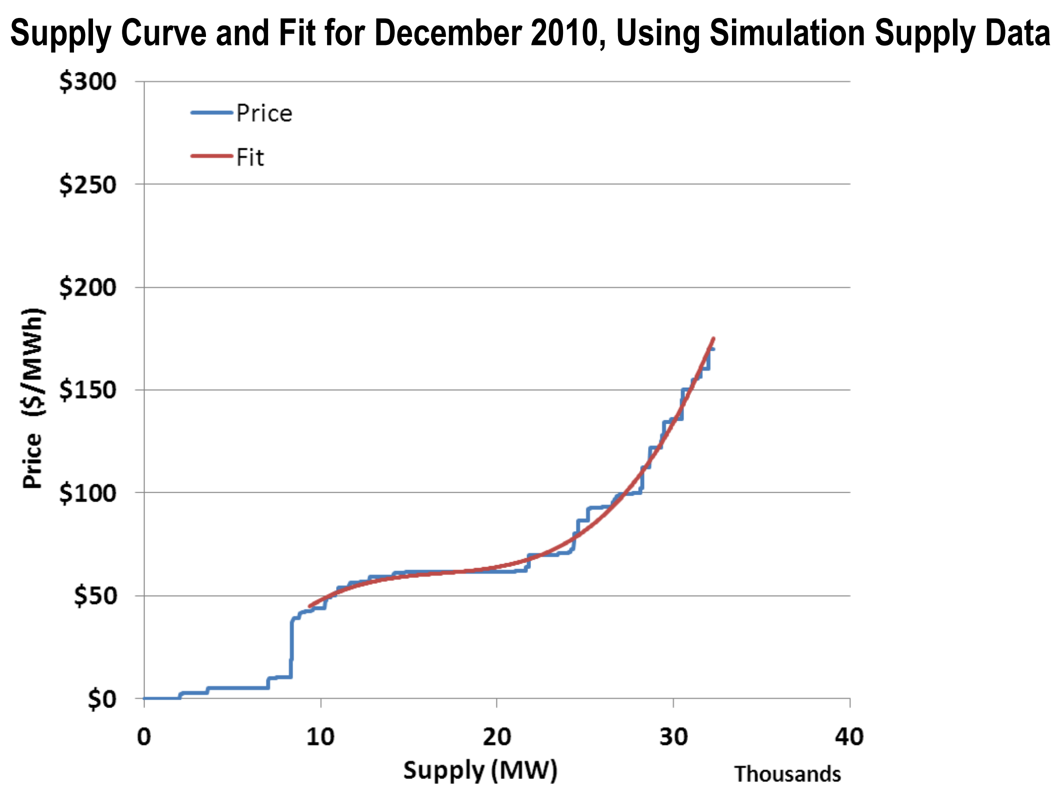
$150
$100
$50
$0
Price ($/MWh)
0
10
20
30
40
Supply (MW)
Thousands


Supply Curve and Fit for December 2010, Using Simulation Supply Data
Price
Fit
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$250
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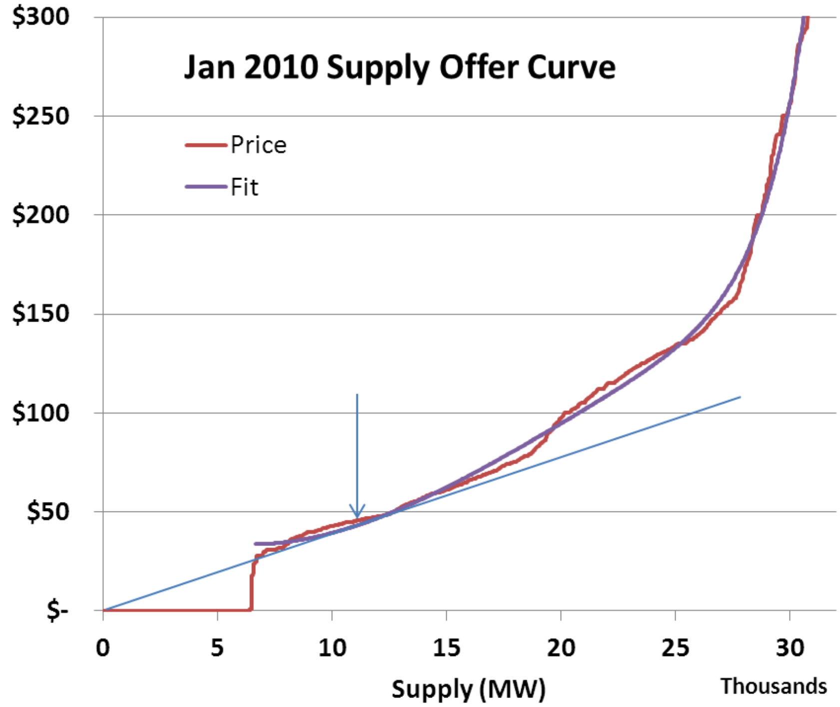
$150
$100
$50
$0
Price ($/MWh)
0
10
20
30
40
Supply (MW)
Thousands


Jan 2010 Supply Offer Curve
Price
Fit
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$150
$100
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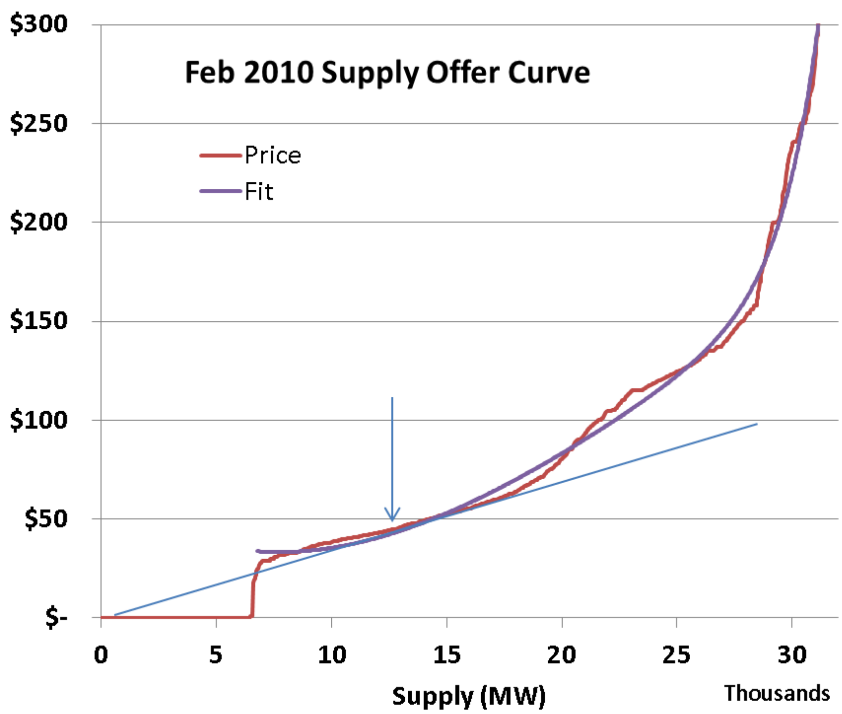
$-
0
5
10
15
20
25
30
Supply (MW)
Thousands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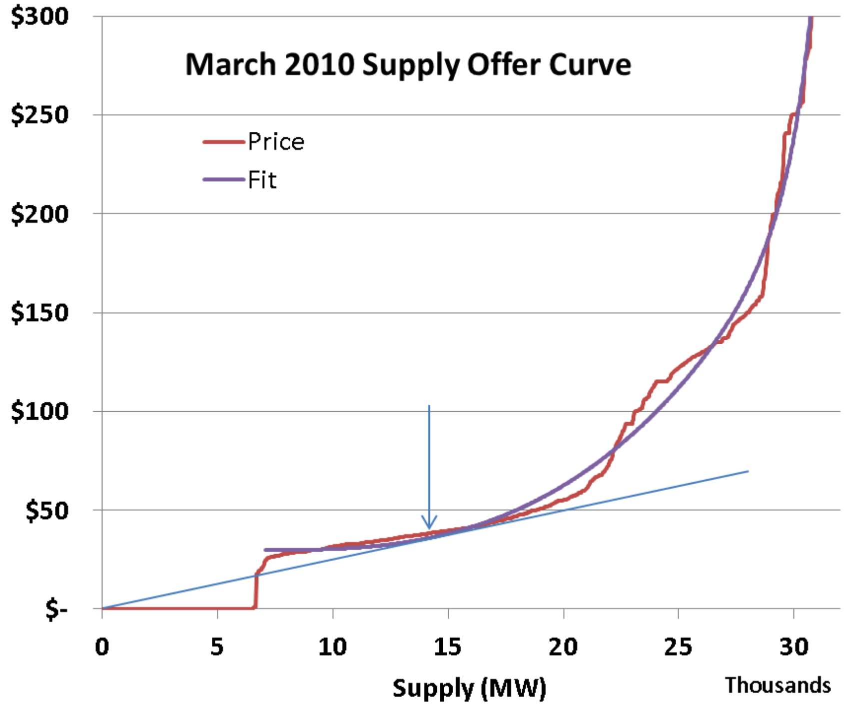
Supply (MW)
Thousands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Price
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$-
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10
15
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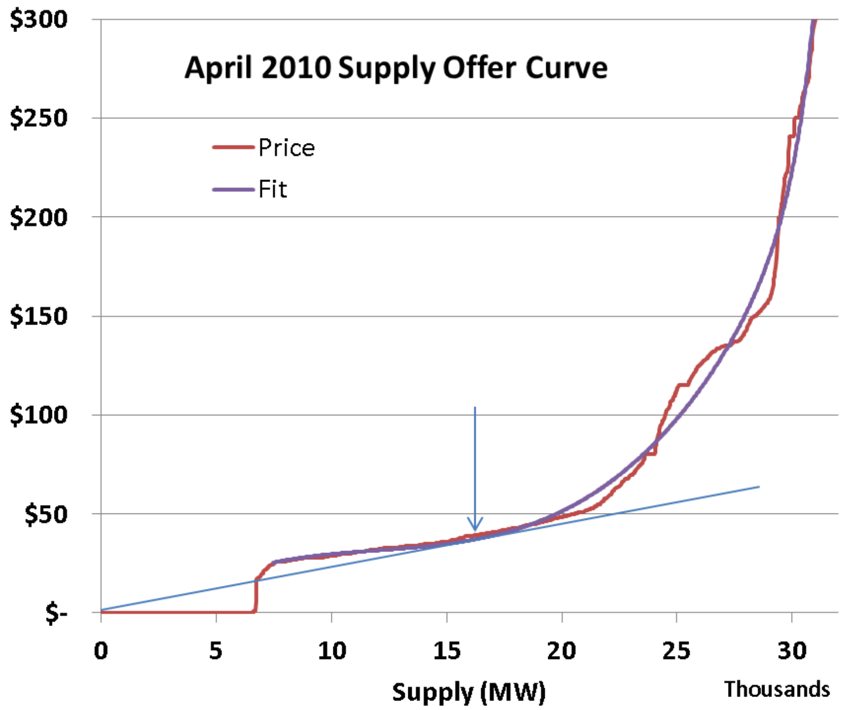
25
30
Supply (MW)
Thousands


April 2010 Supply Offer Curve
Price
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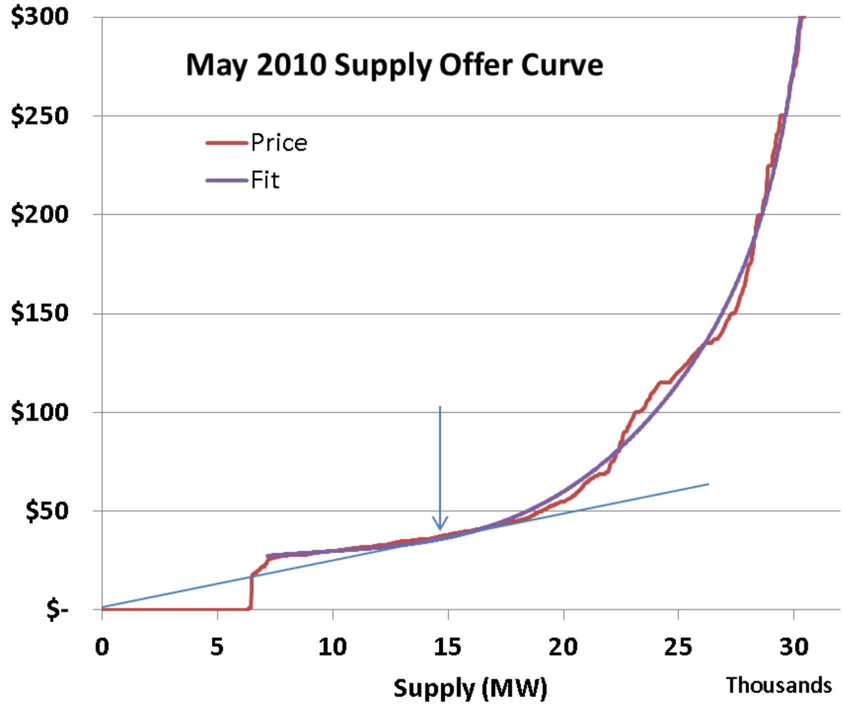
30
Supply (MW)
Thousands


May 2010 Supply Offer Curve
Price
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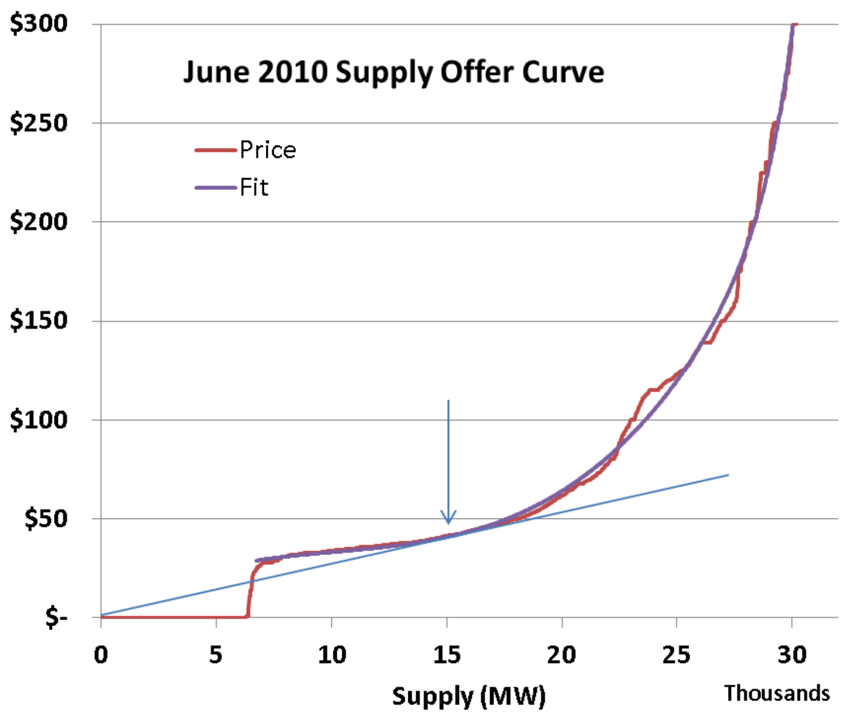
10
15
20
25
30
Supply (MW)
Thousands


June 2010 Supply Offer Curve
Price
Fit
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15
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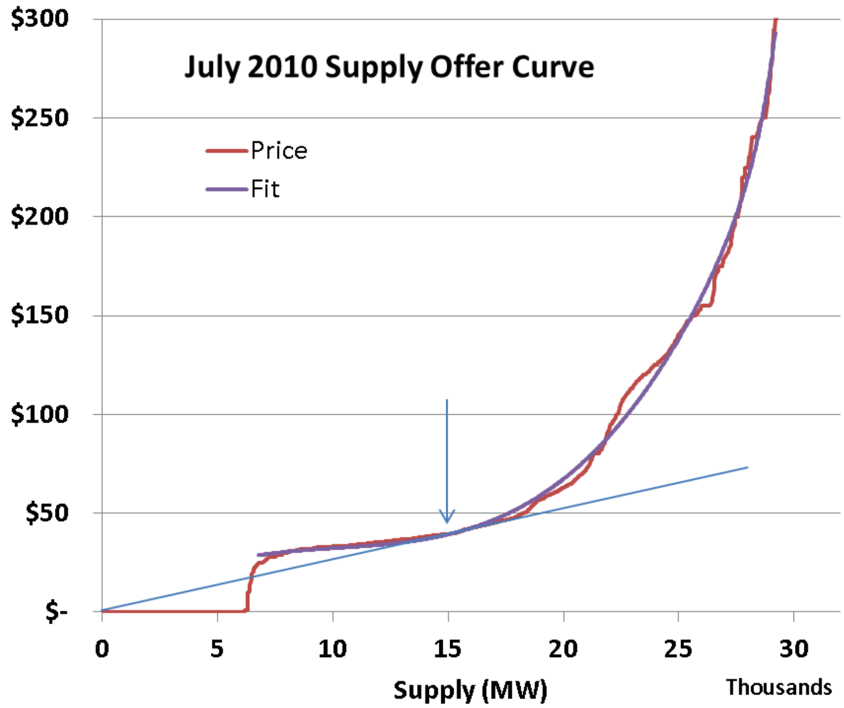
25
30
Supply (MW)
Thousands


July 2010 Supply Offer Curve
Price
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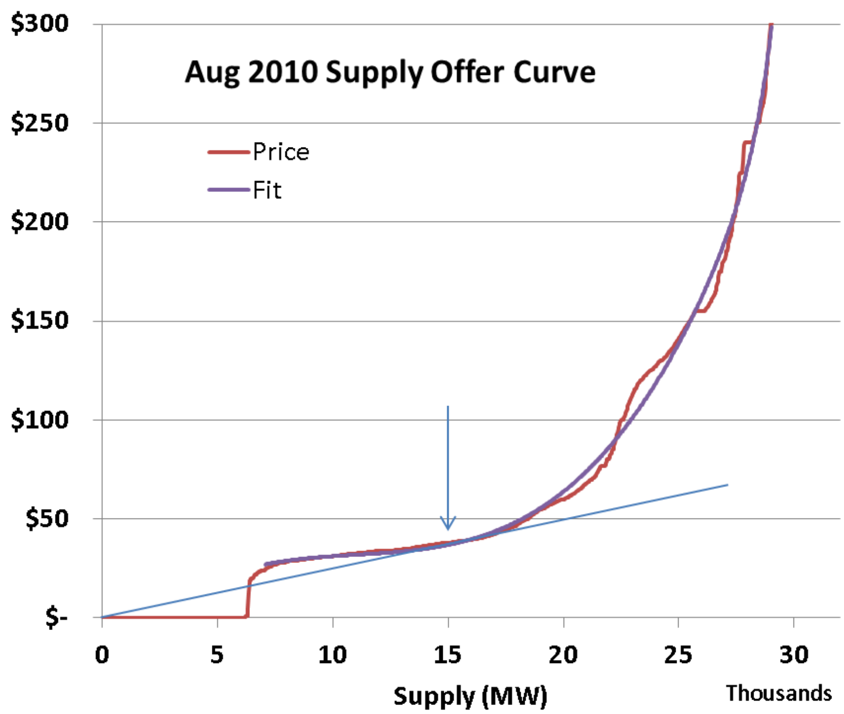
5
10
15
20
25
30
Supply (MW)
Thousands


Aug 2010 Supply Offer Curve
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10
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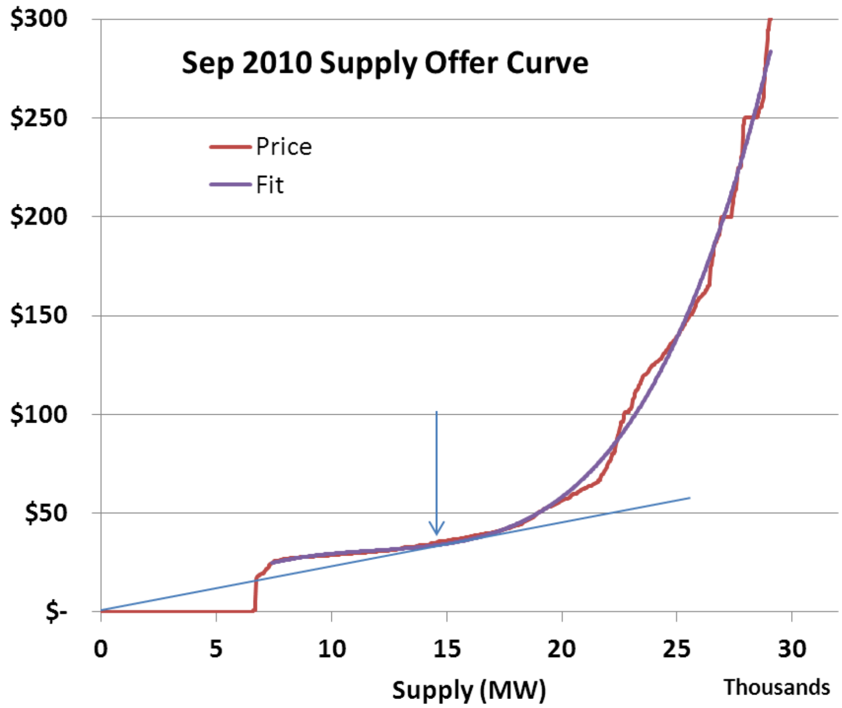
20
25
30
Supply (MW)
Thousands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Price
Fit
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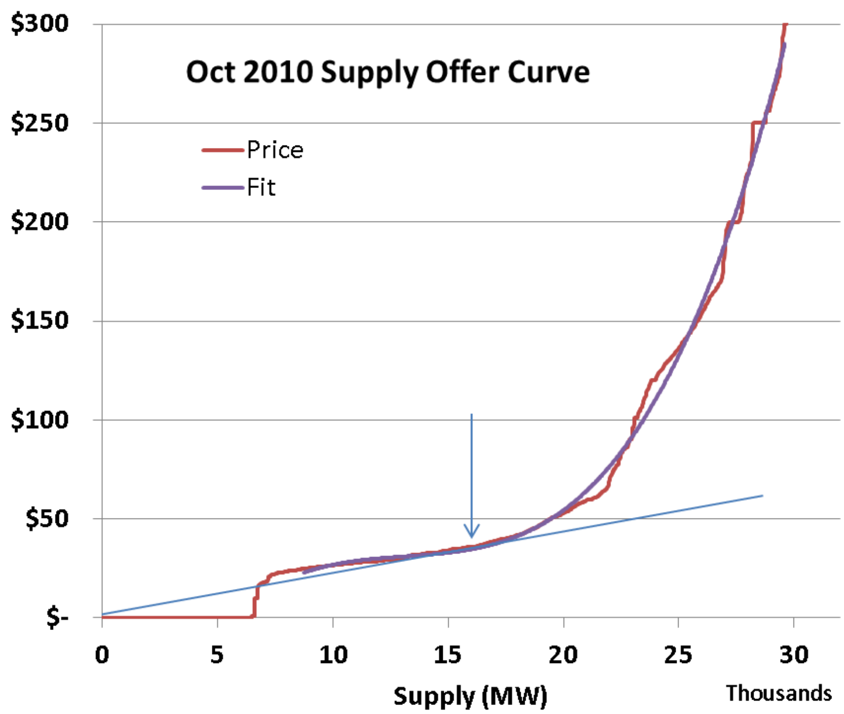
$50
$-
0
5
10
15
20
25
30
Supply (MW)
Thousands


Oct 2010 Supply Offer Curve
Price
Fit
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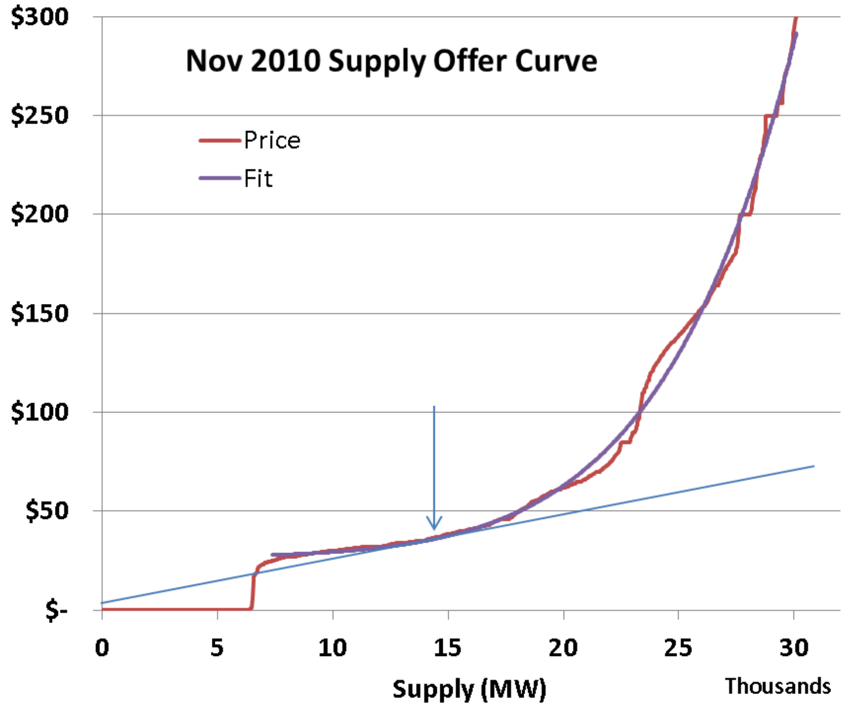
$200
$150
$100
$50
$-
0
5
10
15
20
25
30
Supply (MW)
Thousands


Nov 2010 Supply Offer Curve
Price
Fit
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$100
$50
$-
0
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10
15
20
25
30
Supply (MW)
Thousands

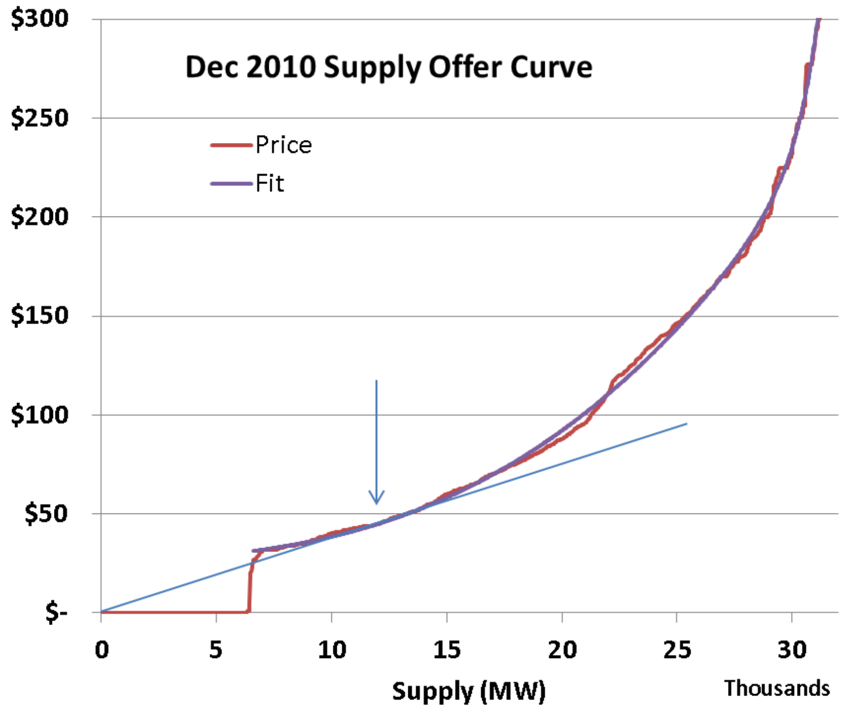

Dec 2010 Supply Offer Curve
Price
Fit
$300
$250
$200
$150
$100
$50
$-
0
5
10
15
20
25
30
Supply (MW)
Thousands

Exhibit B to Attachment 5

Table 1:

Demand Reduction Threshold Prices, Relevant Sample Ranges, and Regression Coefficients for Twelve Reference Months, January through December 2010

Reference Month	Relevant Sample Range ($/MWh)		Demand Reduction Threshold Price ($/MWh)	Regression Coefficients and Statistics $P(x) = e^{(Ax + B)} + C$			
	Low	High		$A * 10^4$	B	C	R-Square
January, 2010	43	109	**55.5**	1.53166	1.11707	29.55111	99.4%
February, 2010	40	102	**51.4**	2.16279	-0.51180	35.66703	99.6%
March, 2010	36	91	**43.6**	3.67979	-4.42848	36.75195	98.6%
April, 2010	31	78	**40.1**	2.43488	-1.96483	30.57315	98.8%
May, 2010	26	67	**38.6**	1.80728	-0.17453	24.77189	99.2%
June, 2010	25	65	**43.2**	1.62306	0.28627	26.21310	98.6%
July, 2010	30	77	**40.9**	2.56201	-1.64788	30.61330	99.6%
August, 2010	29	73	**38.9**	2.40503	-1.36305	28.40910	99.6%
September, 2010	24	61	**36.0**	2.16189	-0.89607	25.03341	99.5%
October, 2010	24	61	**33.8**	1.95688	-0.50270	22.31905	99.7%
November, 2010	21	54	**37.7**	1.46656	0.71542	20.14244	98.5%
December, 2010	33	83	**47.0**	0.84542	2.77812	1.67412	99.8%

Figure 1: Aggregate Monthly Supply Curve and Smooth Approximation to the Relevant Sample Range for January 2010

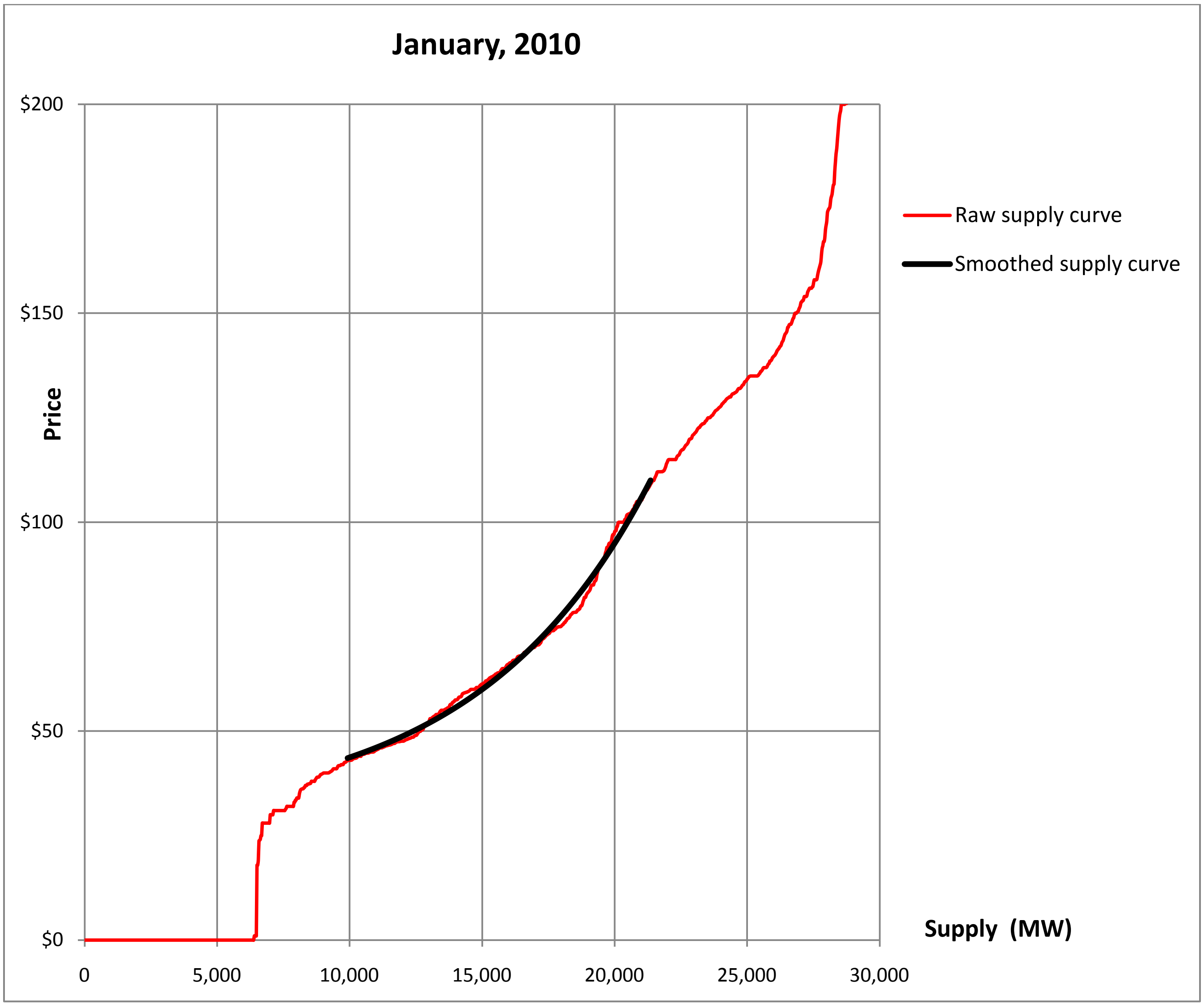


Figure 2: Aggregate Monthly Supply Curve and Smooth Approximation to the Relevant Sample Range for February 2010

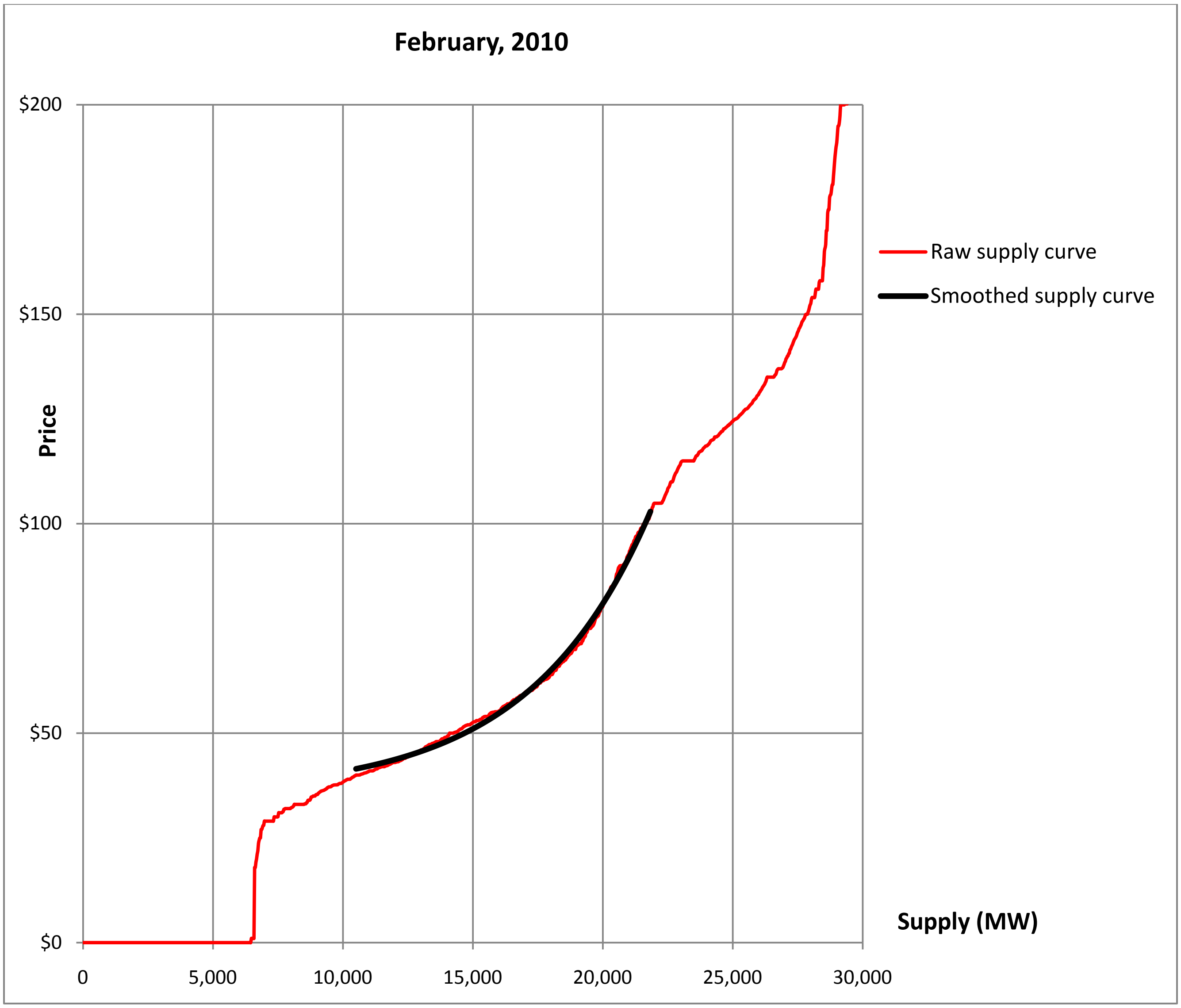


Figure 3: Aggregate Monthly Supply Curve and Smooth Approximation to the Relevant Sample Range for March 2010

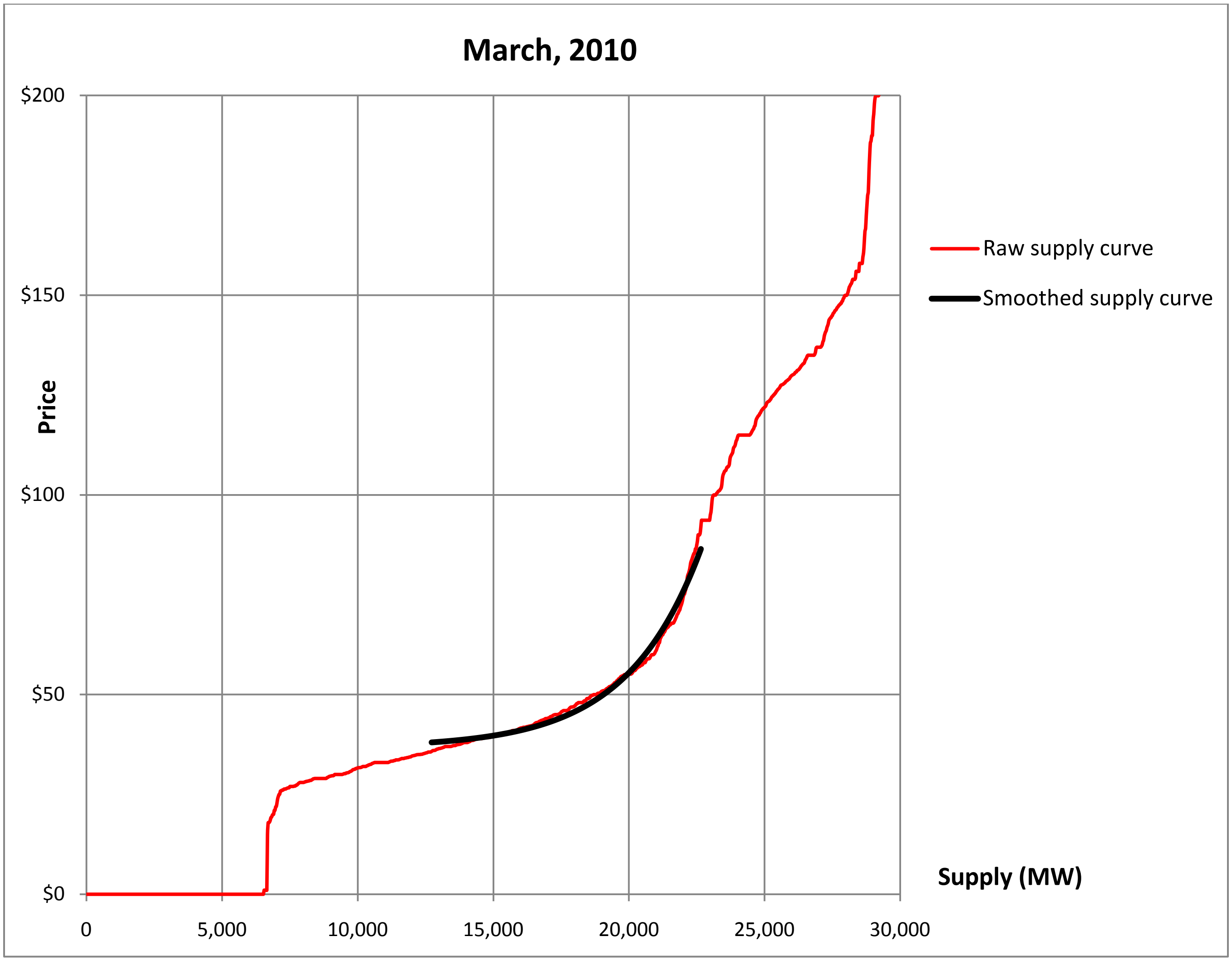


Figure 4: Aggregate Monthly Supply Curve and Smooth Approximation to the Relevant Sample Range for April 2010

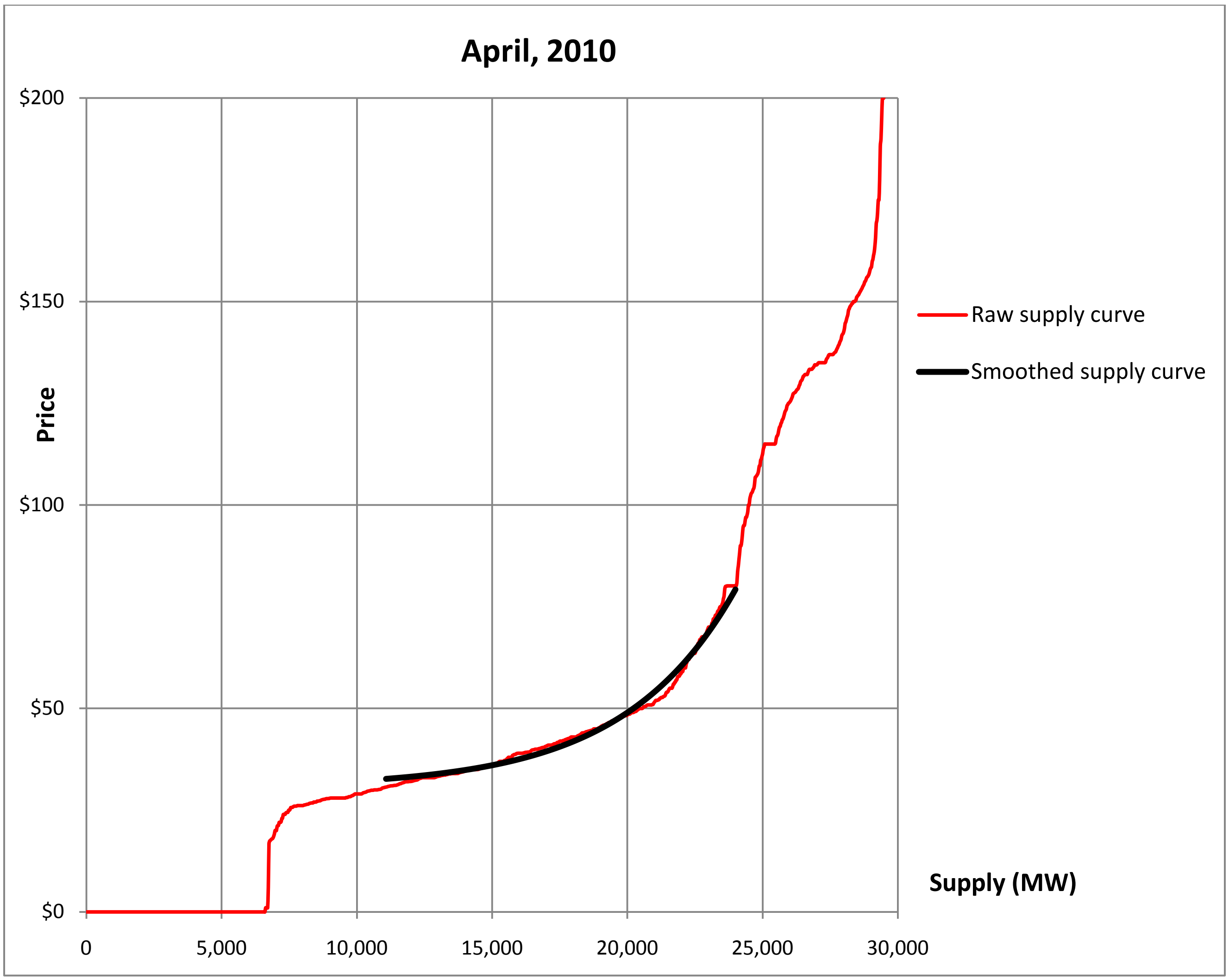


Figure 5: Aggregate Monthly Supply Curve and Smooth Approximation to the Relevant Sample Range for May 2010

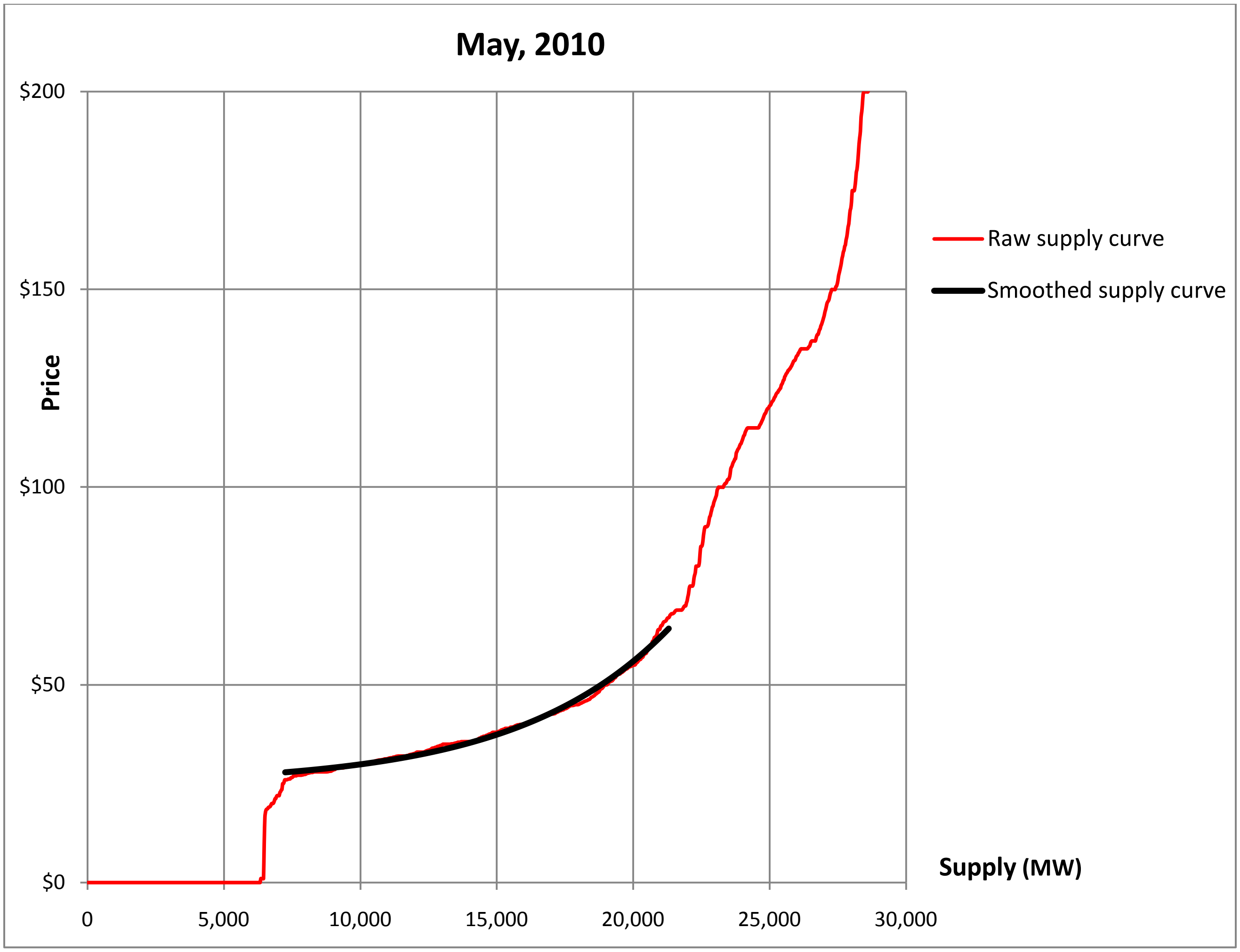


Figure 6: Aggregate Monthly Supply Curve and Smooth Approximation to the Relevant Sample Range for June 2010

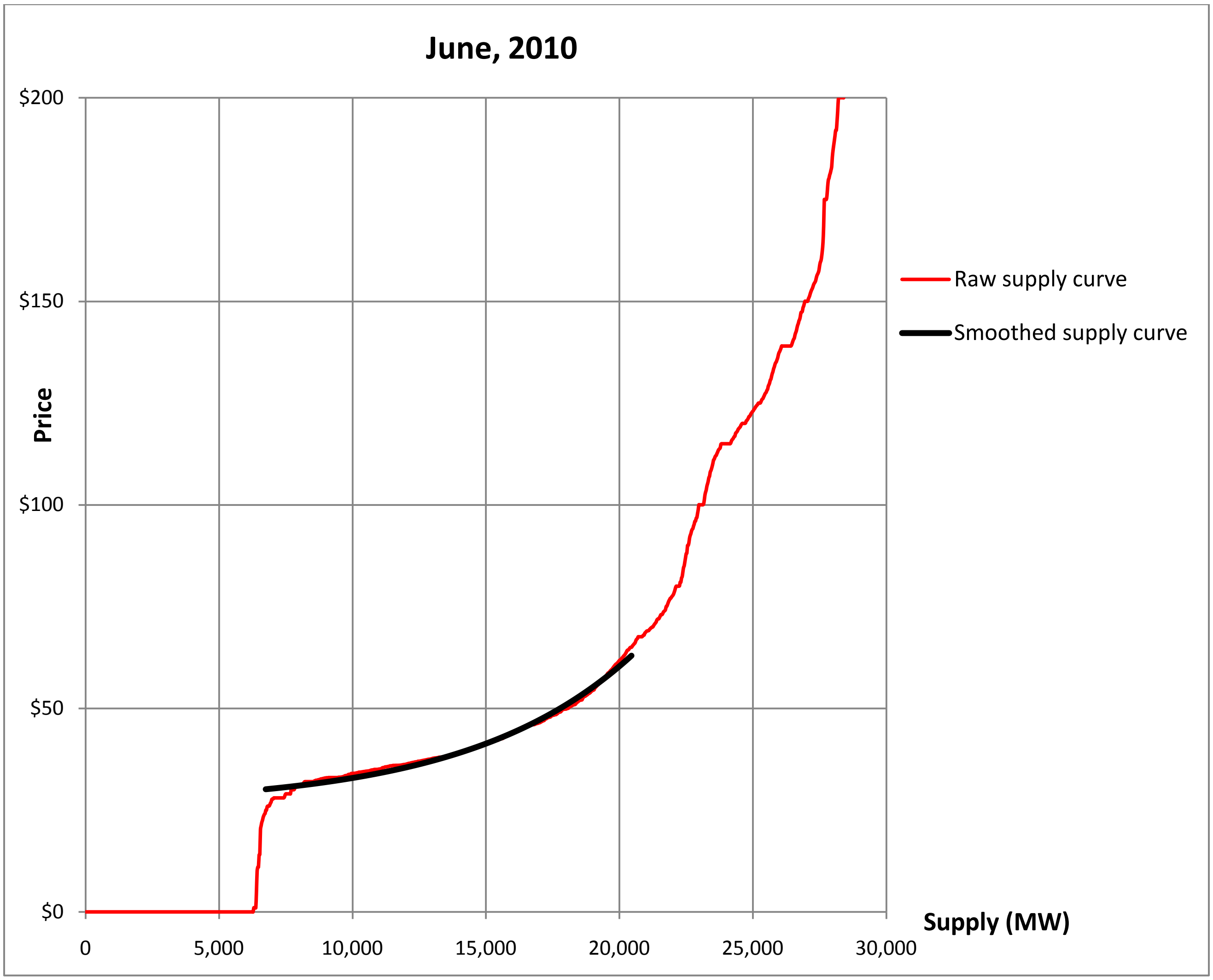


Figure 7: Aggregate Monthly Supply Curve and Smooth Approximation to the Relevant Sample Range for July 2010

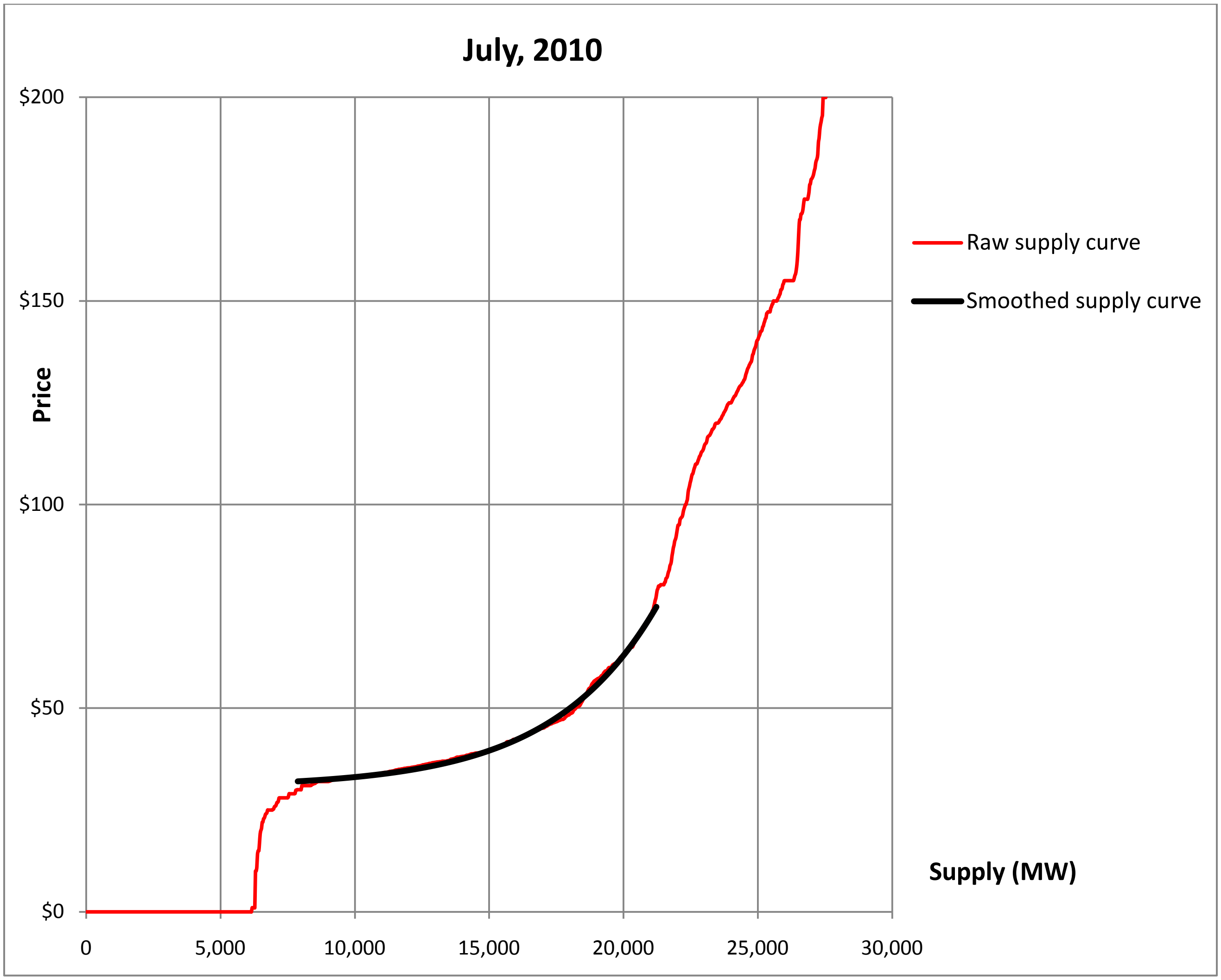


Figure 8: Aggregate Monthly Supply Curve and Smooth Approximation to the Relevant Sample Range for August 2010

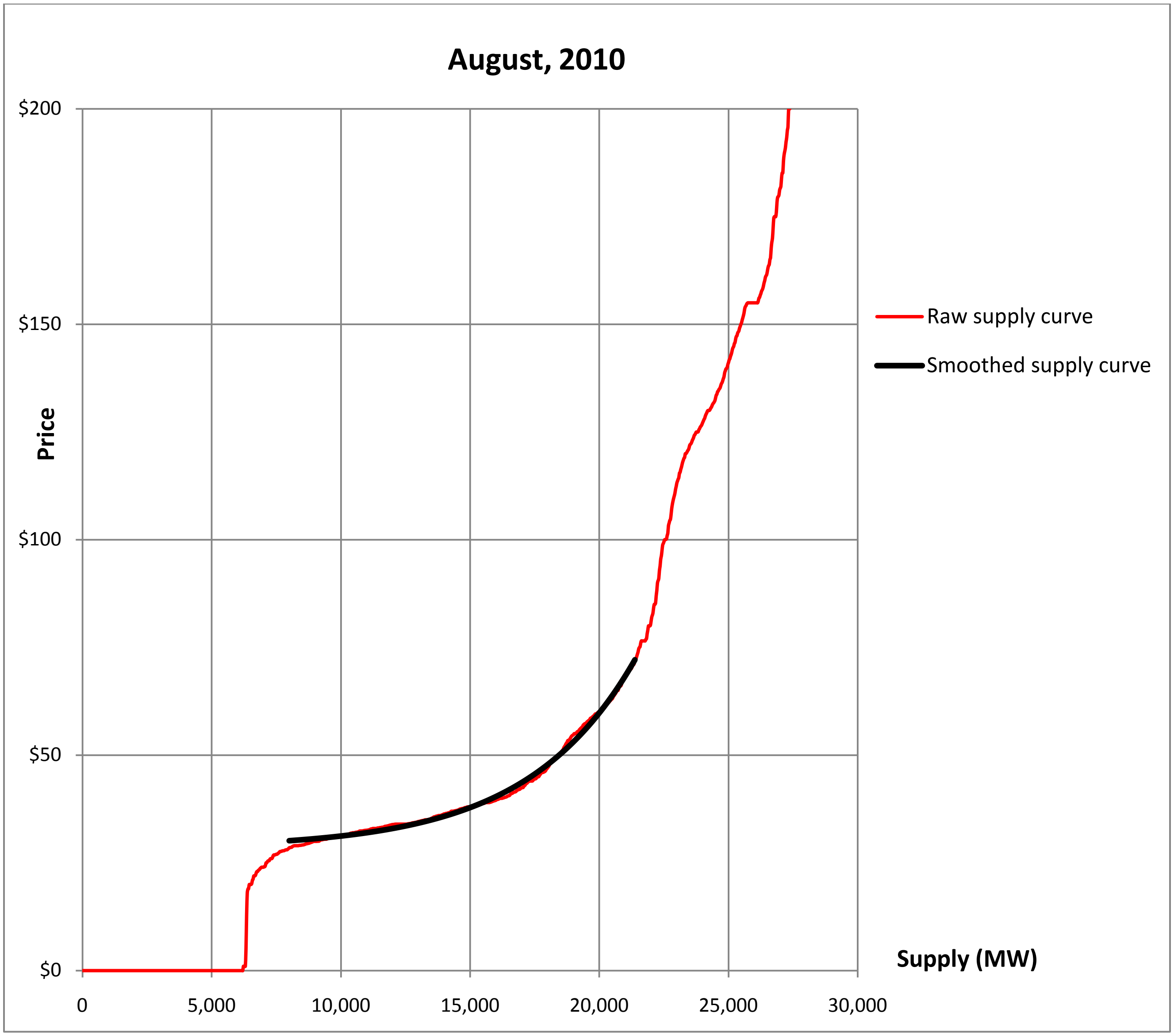


Figure 9: Aggregate Monthly Supply Curve and Smooth Approximation to the Relevant Sample Range for September 2010

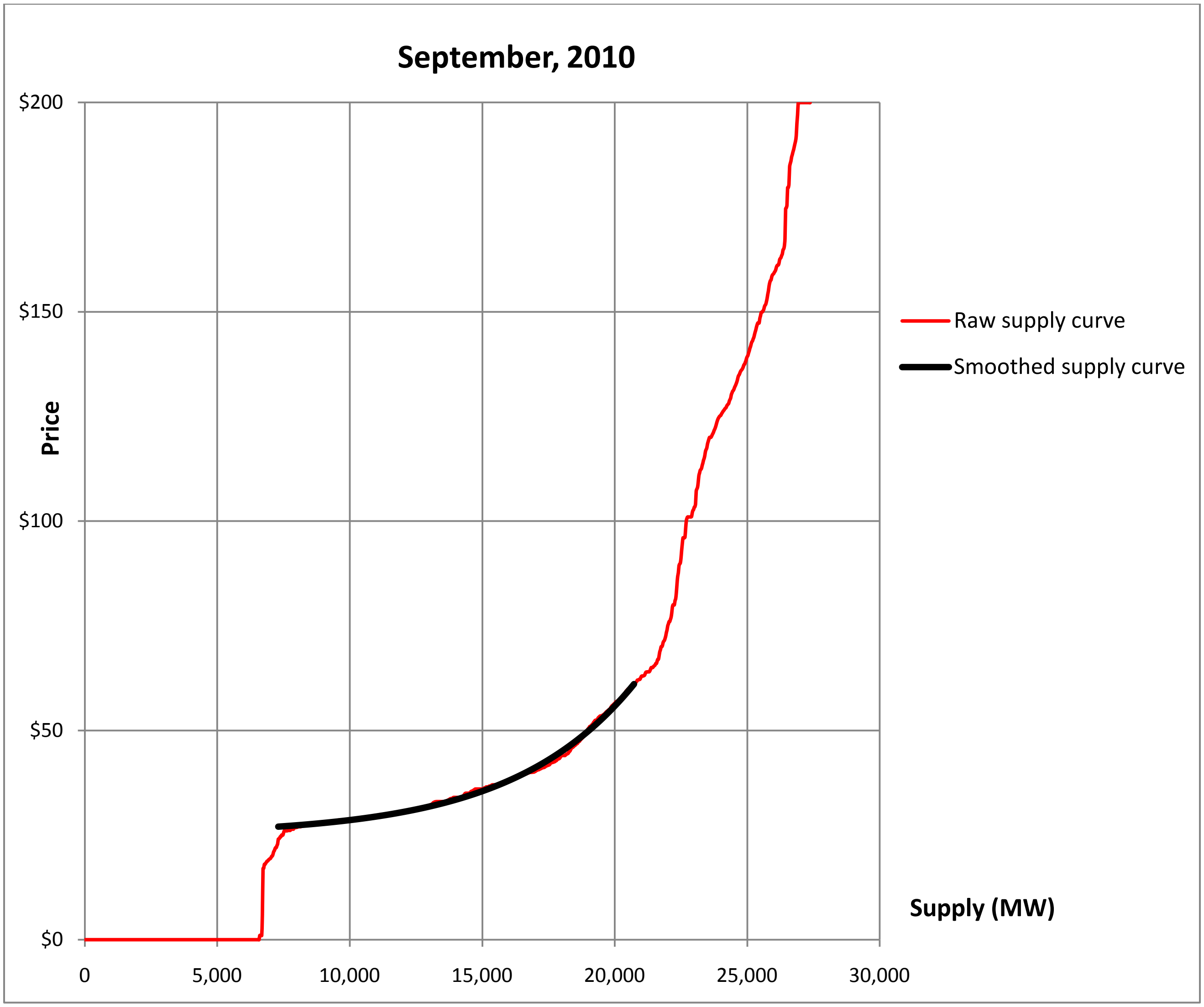


Figure 10: Aggregate Monthly Supply Curve and Smooth Approximation to the Relevant Sample Range for October 2010

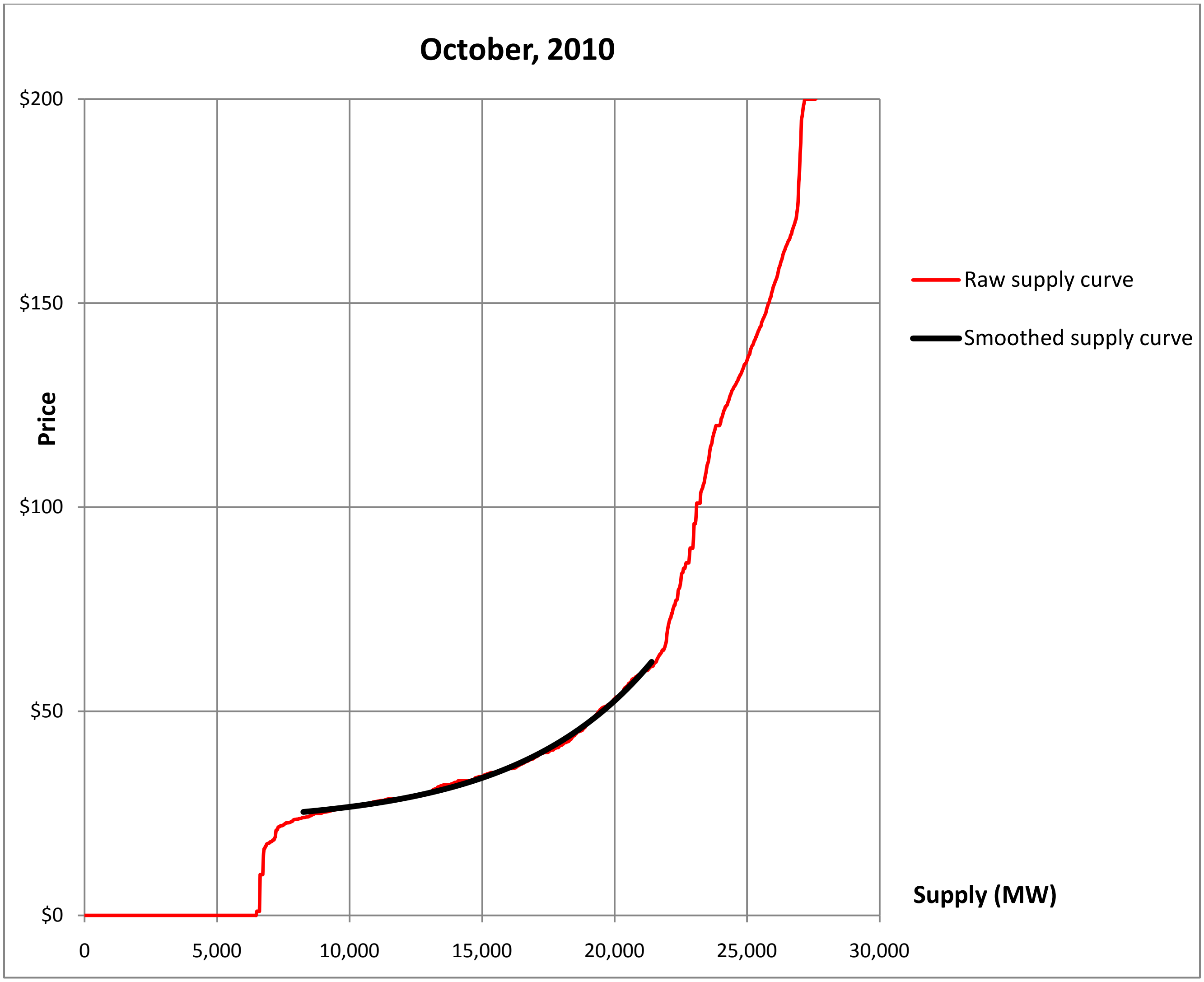


Figure 11: Aggregate Monthly Supply Curve and Smooth Approximation to the Relevant Sample Range for November 2010

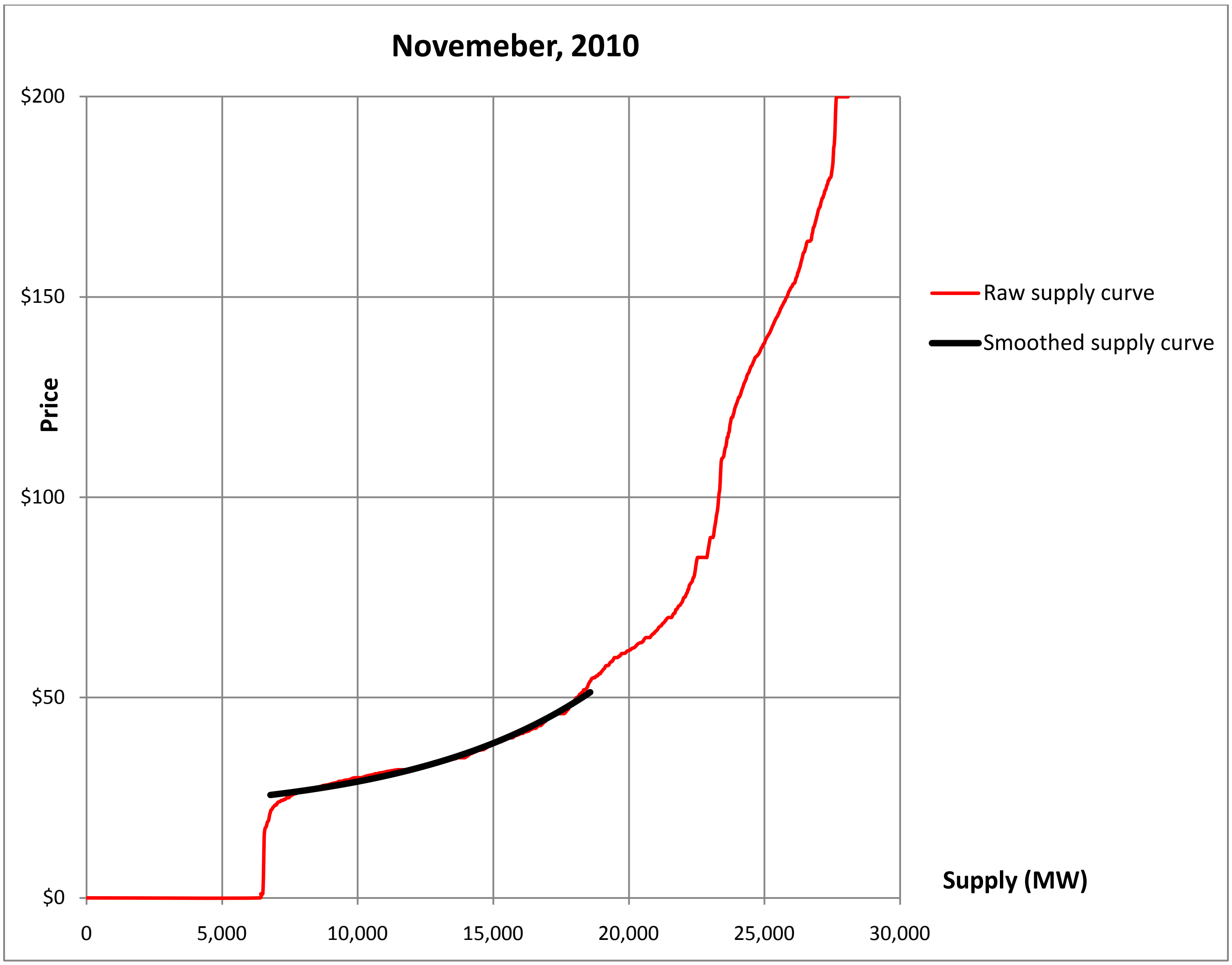
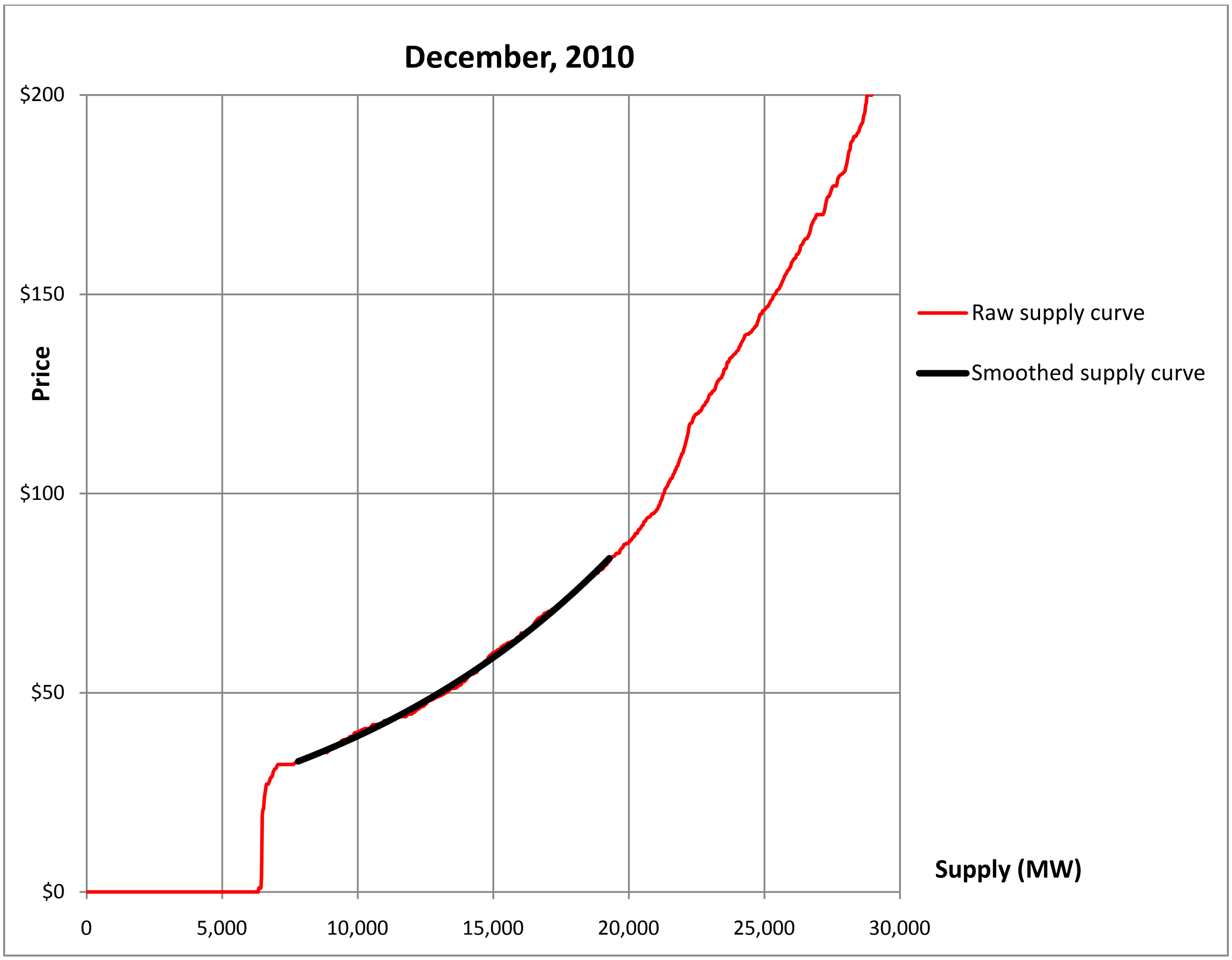


Figure 12: Aggregate Monthly Supply Curve and Smooth Approximation to the Relevant Sample Range for December 2010



Appendix to Exhibit B to Attachment 5

Cumulative Supply (MW)	Offer Price ($/MWh)							
	January	February	March	April	May	June	July	August
0	0	0	0	0	0	0	0	0
25	0	0	0	0	0	0	0	0
50	0	0	0	0	0	0	0	0
75	0	0	0	0	0	0	0	0
100	0	0	0	0	0	0	0	0
125	0	0	0	0	0	0	0	0
150	0	0	0	0	0	0	0	0
175	0	0	0	0	0	0	0	0
200	0	0	0	0	0	0	0	0
225	0	0	0	0	0	0	0	0
250	0	0	0	0	0	0	0	0
275	0	0	0	0	0	0	0	0
300	0	0	0	0	0	0	0	0
325	0	0	0	0	0	0	0	0
350	0	0	0	0	0	0	0	0
375	0	0	0	0	0	0	0	0
400	0	0	0	0	0	0	0	0
425	0	0	0	0	0	0	0	0
450	0	0	0	0	0	0	0	0
475	0	0	0	0	0	0	0	0
500	0	0	0	0	0	0	0	0
525	0	0	0	0	0	0	0	0
550	0	0	0	0	0	0	0	0
575	0	0	0	0	0	0	0	0
600	0	0	0	0	0	0	0	0
625	0	0	0	0	0	0	0	0
650	0	0	0	0	0	0	0	0
675	0	0	0	0	0	0	0	0
700	0	0	0	0	0	0	0	0
725	0	0	0	0	0	0	0	0
750	0	0	0	0	0	0	0	0
775	0	0	0	0	0	0	0	0
800	0	0	0	0	0	0	0	0
825	0	0	0	0	0	0	0	0
850	0	0	0	0	0	0	0	0
875	0	0	0	0	0	0	0	0
900	0	0	0	0	0	0	0	0
925	0	0	0	0	0	0	0	0
950	0	0	0	0	0	0	0	0
975	0	0	0	0	0	0	0	0
1,000	0	0	0	0	0	0	0	0
1,025	0	0	0	0	0	0	0	0
1,050	0	0	0	0	0	0	0	0
1,075	0	0	0	0	0	0	0	0

1,100	0	0	0	0	0	0	0	0
1,125	0	0	0	0	0	0	0	0
1,150	0	0	0	0	0	0	0	0
1,175	0	0	0	0	0	0	0	0
1,200	0	0	0	0	0	0	0	0
1,225	0	0	0	0	0	0	0	0
1,250	0	0	0	0	0	0	0	0
1,275	0	0	0	0	0	0	0	0
1,300	0	0	0	0	0	0	0	0
1,325	0	0	0	0	0	0	0	0
1,350	0	0	0	0	0	0	0	0
1,375	0	0	0	0	0	0	0	0
1,400	0	0	0	0	0	0	0	0
1,425	0	0	0	0	0	0	0	0
1,450	0	0	0	0	0	0	0	0
1,475	0	0	0	0	0	0	0	0
1,500	0	0	0	0	0	0	0	0
1,525	0	0	0	0	0	0	0	0
1,550	0	0	0	0	0	0	0	0
1,575	0	0	0	0	0	0	0	0
1,600	0	0	0	0	0	0	0	0
1,625	0	0	0	0	0	0	0	0
1,650	0	0	0	0	0	0	0	0
1,675	0	0	0	0	0	0	0	0
1,700	0	0	0	0	0	0	0	0
1,725	0	0	0	0	0	0	0	0
1,750	0	0	0	0	0	0	0	0
1,775	0	0	0	0	0	0	0	0
1,800	0	0	0	0	0	0	0	0
1,825	0	0	0	0	0	0	0	0
1,850	0	0	0	0	0	0	0	0
1,875	0	0	0	0	0	0	0	0
1,900	0	0	0	0	0	0	0	0
1,925	0	0	0	0	0	0	0	0
1,950	0	0	0	0	0	0	0	0
1,975	0	0	0	0	0	0	0	0
2,000	0	0	0	0	0	0	0	0
2,025	0	0	0	0	0	0	0	0
2,050	0	0	0	0	0	0	0	0
2,075	0	0	0	0	0	0	0	0
2,100	0	0	0	0	0	0	0	0
2,125	0	0	0	0	0	0	0	0
2,150	0	0	0	0	0	0	0	0
2,175	0	0	0	0	0	0	0	0
2,200	0	0	0	0	0	0	0	0
2,225	0	0	0	0	0	0	0	0
2,250	0	0	0	0	0	0	0	0

2,275	0	0	0	0	0	0	0	0
2,300	0	0	0	0	0	0	0	0
2,325	0	0	0	0	0	0	0	0
2,350	0	0	0	0	0	0	0	0
2,375	0	0	0	0	0	0	0	0
2,400	0	0	0	0	0	0	0	0
2,425	0	0	0	0	0	0	0	0
2,450	0	0	0	0	0	0	0	0
2,475	0	0	0	0	0	0	0	0
2,500	0	0	0	0	0	0	0	0
2,525	0	0	0	0	0	0	0	0
2,550	0	0	0	0	0	0	0	0
2,575	0	0	0	0	0	0	0	0
2,600	0	0	0	0	0	0	0	0
2,625	0	0	0	0	0	0	0	0
2,650	0	0	0	0	0	0	0	0
2,675	0	0	0	0	0	0	0	0
2,700	0	0	0	0	0	0	0	0
2,725	0	0	0	0	0	0	0	0
2,750	0	0	0	0	0	0	0	0
2,775	0	0	0	0	0	0	0	0
2,800	0	0	0	0	0	0	0	0
2,825	0	0	0	0	0	0	0	0
2,850	0	0	0	0	0	0	0	0
2,875	0	0	0	0	0	0	0	0
2,900	0	0	0	0	0	0	0	0
2,925	0	0	0	0	0	0	0	0
2,950	0	0	0	0	0	0	0	0
2,975	0	0	0	0	0	0	0	0
3,000	0	0	0	0	0	0	0	0
3,025	0	0	0	0	0	0	0	0
3,050	0	0	0	0	0	0	0	0
3,075	0	0	0	0	0	0	0	0
3,100	0	0	0	0	0	0	0	0
3,125	0	0	0	0	0	0	0	0
3,150	0	0	0	0	0	0	0	0
3,175	0	0	0	0	0	0	0	0
3,200	0	0	0	0	0	0	0	0
3,225	0	0	0	0	0	0	0	0
3,250	0	0	0	0	0	0	0	0
3,275	0	0	0	0	0	0	0	0
3,300	0	0	0	0	0	0	0	0
3,325	0	0	0	0	0	0	0	0
3,350	0	0	0	0	0	0	0	0
3,375	0	0	0	0	0	0	0	0
3,400	0	0	0	0	0	0	0	0
3,425	0	0	0	0	0	0	0	0

3,450	0	0	0	0	0	0	0	0
3,475	0	0	0	0	0	0	0	0
3,500	0	0	0	0	0	0	0	0
3,525	0	0	0	0	0	0	0	0
3,550	0	0	0	0	0	0	0	0
3,575	0	0	0	0	0	0	0	0
3,600	0	0	0	0	0	0	0	0
3,625	0	0	0	0	0	0	0	0
3,650	0	0	0	0	0	0	0	0
3,675	0	0	0	0	0	0	0	0
3,700	0	0	0	0	0	0	0	0
3,725	0	0	0	0	0	0	0	0
3,750	0	0	0	0	0	0	0	0
3,775	0	0	0	0	0	0	0	0
3,800	0	0	0	0	0	0	0	0
3,825	0	0	0	0	0	0	0	0
3,850	0	0	0	0	0	0	0	0
3,875	0	0	0	0	0	0	0	0
3,900	0	0	0	0	0	0	0	0
3,925	0	0	0	0	0	0	0	0
3,950	0	0	0	0	0	0	0	0
3,975	0	0	0	0	0	0	0	0
4,000	0	0	0	0	0	0	0	0
4,025	0	0	0	0	0	0	0	0
4,050	0	0	0	0	0	0	0	0
4,075	0	0	0	0	0	0	0	0
4,100	0	0	0	0	0	0	0	0
4,125	0	0	0	0	0	0	0	0
4,150	0	0	0	0	0	0	0	0
4,175	0	0	0	0	0	0	0	0
4,200	0	0	0	0	0	0	0	0
4,225	0	0	0	0	0	0	0	0
4,250	0	0	0	0	0	0	0	0
4,275	0	0	0	0	0	0	0	0
4,300	0	0	0	0	0	0	0	0
4,325	0	0	0	0	0	0	0	0
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4,375	0	0	0	0	0	0	0	0
4,400	0	0	0	0	0	0	0	0
4,425	0	0	0	0	0	0	0	0
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4,475	0	0	0	0	0	0	0	0
4,500	0	0	0	0	0	0	0	0
4,525	0	0	0	0	0	0	0	0
4,550	0	0	0	0	0	0	0	0
4,575	0	0	0	0	0	0	0	0
4,600	0	0	0	0	0	0	0	0

4,625	0	0	0	0	0	0	0	0
4,650	0	0	0	0	0	0	0	0
4,675	0	0	0	0	0	0	0	0
4,700	0	0	0	0	0	0	0	0
4,725	0	0	0	0	0	0	0	0
4,750	0	0	0	0	0	0	0	0
4,775	0	0	0	0	0	0	0	0
4,800	0	0	0	0	0	0	0	0
4,825	0	0	0	0	0	0	0	0
4,850	0	0	0	0	0	0	0	0
4,875	0	0	0	0	0	0	0	0
4,900	0	0	0	0	0	0	0	0
4,925	0	0	0	0	0	0	0	0
4,950	0	0	0	0	0	0	0	0
4,975	0	0	0	0	0	0	0	0
5,000	0	0	0	0	0	0	0	0
5,025	0	0	0	0	0	0	0	0
5,050	0	0	0	0	0	0	0	0
5,075	0	0	0	0	0	0	0	0
5,100	0	0	0	0	0	0	0	0
5,125	0	0	0	0	0	0	0	0
5,150	0	0	0	0	0	0	0	0
5,175	0	0	0	0	0	0	0	0
5,200	0	0	0	0	0	0	0	0
5,225	0	0	0	0	0	0	0	0
5,250	0	0	0	0	0	0	0	0
5,275	0	0	0	0	0	0	0	0
5,300	0	0	0	0	0	0	0	0
5,325	0	0	0	0	0	0	0	0
5,350	0	0	0	0	0	0	0	0
5,375	0	0	0	0	0	0	0	0
5,400	0	0	0	0	0	0	0	0
5,425	0	0	0	0	0	0	0	0
5,450	0	0	0	0	0	0	0	0
5,475	0	0	0	0	0	0	0	0
5,500	0	0	0	0	0	0	0	0
5,525	0	0	0	0	0	0	0	0
5,550	0	0	0	0	0	0	0	0
5,575	0	0	0	0	0	0	0	0
5,600	0	0	0	0	0	0	0	0
5,625	0	0	0	0	0	0	0	0
5,650	0	0	0	0	0	0	0	0
5,675	0	0	0	0	0	0	0	0
5,700	0	0	0	0	0	0	0	0
5,725	0	0	0	0	0	0	0	0
5,750	0	0	0	0	0	0	0	0
5,775	0	0	0	0	0	0	0	0

5,800	0	0	0	0	0	0	0	0
5,825	0	0	0	0	0	0	0	0
5,850	0	0	0	0	0	0	0	0
5,875	0	0	0	0	0	0	0	0
5,900	0	0	0	0	0	0	0	0
5,925	0	0	0	0	0	0	0	0
5,950	0	0	0	0	0	0	0	0
5,975	0	0	0	0	0	0	0	0
6,000	0	0	0	0	0	0	0	0
6,025	0	0	0	0	0	0	0	0
6,050	0	0	0	0	0	0	0	0
6,075	0	0	0	0	0	0	0	0
6,100	0	0	0	0	0	0	0	0
6,125	0	0	0	0	0	0	0	0
6,150	0	0	0	0	0	0	0	0
6,175	0	0	0	0	0	0	0	0
6,200	0	0	0	0	0	0	1	0
6,225	0	0	0	0	0	0	1	1
6,250	0	0	0	0	0	0	1	1
6,275	0	0	0	0	0	0	1	1
6,300	0	0	0	0	0	1	1	1
6,325	0	0	0	0	0	1	10	5
6,350	0	0	0	0	1	1	10	13
6,375	0	0	0	0	1	1	11	18
6,400	1	0	0	0	1	5	14	19
6,425	1	0	0	0	1	10	15	19
6,450	1	0	0	0	1	11	15	20
6,475	1	1	0	0	10	11	17	20
6,500	18	1	0	0	17	14	19	20
6,525	18	1	0	0	18	14	20	20
6,550	19	1	1	0	18	20	21	20
6,575	24	1	1	0	19	21	22	21
6,600	24	18	1	0	19	22	22	21
6,625	24	18	1	1	19	22	23	22
6,650	25	19	1	1	19	23	23	22
6,675	25	20	15	1	19	24	23	22
6,700	28	21	18	1	19	24	24	22
6,725	28	22	18	6	20	24	24	23
6,750	28	24	18	17	20	25	24	23
6,775	28	24	19	17	20	25	25	23
6,800	28	25	19	18	20	26	25	23
6,825	28	25	19	18	20	26	25	23
6,850	28	27	20	18	21	26	25	24
6,875	28	27	20	18	21	26	25	24
6,900	28	28	20	18	21	26	25	24
6,925	28	28	21	19	22	27	25	24
6,950	28	28	21	19	22	27	25	24

6,975	28	29	22	20	22	28	25	24
7,000	30	29	22	20	22	28	25	24
7,025	30	29	23	20	22	28	26	24
7,050	30	29	24	21	23	28	26	24
7,075	30	29	25	21	23	28	26	24
7,100	30	29	25	21	23	28	26	25
7,125	31	29	25	22	24	28	27	25
7,150	31	29	26	22	25	28	27	25
7,175	31	29	26	22	25	28	27	25
7,200	31	29	26	22	25	28	28	26
7,225	31	29	26	23	26	28	28	26
7,250	31	29	26	23	26	28	28	26
7,275	31	29	26	24	26	28	28	26
7,300	31	29	26	24	26	28	28	26
7,325	31	29	26	24	26	28	28	26
7,350	31	30	26	24	26	28	28	26
7,375	31	30	27	24	26	28	28	27
7,400	31	30	27	24	26	28	28	27
7,425	31	30	27	24	26	28	28	27
7,450	31	30	27	24	26	28	28	27
7,475	31	30	27	25	27	29	28	27
7,500	31	30	27	25	27	29	28	27
7,525	31	31	27	25	27	29	28	27
7,550	31	31	27	26	27	29	28	27
7,575	31	31	27	26	27	29	29	27
7,600	32	31	27	26	27	29	29	27
7,625	32	31	27	26	27	29	29	28
7,650	32	31	27	26	27	29	29	28
7,675	32	31	27	26	27	29	29	28
7,700	32	31	27	26	27	30	29	28
7,725	32	32	27	26	27	30	29	28
7,750	32	32	27	26	27	30	29	28
7,775	32	32	27	26	27	30	29	28
7,800	32	32	28	26	27	30	29	28
7,825	32	32	28	26	27	30	30	28
7,850	32	32	28	26	27	31	30	28
7,875	32	32	28	26	27	31	30	28
7,900	33	32	28	26	27	31	30	28
7,925	33	32	28	26	27	31	30	28
7,950	34	32	28	26	27	31	30	28
7,975	34	32	28	26	27	31	30	28
8,000	34	32	28	26	27	31	30	29
8,025	34	32	28	26	28	31	30	29
8,050	34	32	28	26	28	31	31	29
8,075	34	32	28	26	28	31	31	29
8,100	35	33	28	26	28	31	31	29
8,125	36	33	28	26	28	31	31	29

8,150	36	33	28	26	28	32	31	29
8,175	36	33	28	26	28	32	31	29
8,200	36	33	28	26	28	32	31	29
8,225	36	33	28	27	28	32	31	29
8,250	36	33	29	27	28	32	31	29
8,275	37	33	29	27	28	32	31	29
8,300	37	33	29	27	28	32	31	29
8,325	37	33	29	27	28	32	31	29
8,350	37	33	29	27	28	32	31	29
8,375	37	33	29	27	28	32	31	29
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8,650	38	34	29	27	28	32	32	29
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8,700	38	34	29	28	28	32	32	29
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8,825	39	35	29	28	28	33	32	30
8,850	39	35	29	28	28	33	32	30
8,875	39	35	29	28	28	33	32	30
8,900	40	35	29	28	28	33	32	30
8,925	40	35	29	28	28	33	32	30
8,950	40	35	30	28	28	33	32	30
8,975	40	35	30	28	28	33	32	30
9,000	40	35	30	28	28	33	32	30
9,025	40	35	30	28	29	33	32	30
9,050	40	36	30	28	29	33	32	30
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9,150	40	36	30	28	29	33	32	30
9,175	40	36	30	28	29	33	32	30
9,200	40	36	30	28	29	33	32	30
9,225	40	36	30	28	29	33	32	30
9,250	40	36	30	28	29	33	32	30
9,275	40	36	30	28	29	33	33	30
9,300	40	37	30	28	29	33	33	30

9,325	40	37	30	28	29	33	33	30
9,350	41	37	30	28	29	33	33	30
9,375	41	37	30	28	29	33	33	30
9,400	41	37	30	28	29	33	33	31
9,425	41	37	30	28	29	33	33	31
9,450	41	37	30	28	29	33	33	31
9,475	41	37	30	28	29	33	33	31
9,500	41	37	30	28	29	33	33	31
9,525	41	37	30	28	29	33	33	31
9,550	42	37	30	28	29	33	33	31
9,575	42	37	30	28	29	33	33	31
9,600	42	38	30	28	29	33	33	31
9,625	42	38	30	28	30	33	33	31
9,650	42	38	30	28	30	33	33	31
9,675	42	38	31	28	30	33	33	31
9,700	42	38	31	28	30	33	33	31
9,725	42	38	31	28	30	33	33	31
9,750	42	38	31	28	30	33	33	31
9,775	42	38	31	28	30	33	33	31
9,800	43	38	31	29	30	34	33	31
9,825	43	38	31	29	30	34	33	31
9,850	43	38	31	29	30	34	33	31
9,875	43	38	31	29	30	34	33	31
9,900	43	38	31	29	30	34	33	31
9,925	43	38	31	29	30	34	33	31
9,950	43	38	31	29	30	34	33	31
9,975	43	38	32	29	30	34	33	31
10,000	43	38	32	29	30	34	33	31
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10,050	43	39	32	29	30	34	33	31
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10,150	43	39	32	29	30	34	33	31
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10,200	44	39	32	29	30	34	33	31
10,225	44	39	32	29	30	34	33	31
10,250	44	39	32	29	30	34	33	32
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19,950	97	80	55	48	55	61	63	60
19,975	97	80	55	48	55	62	63	60
20,000	98	80	55	48	55	62	63	60
20,025	98	81	55	49	55	62	63	60
20,050	98	81	55	49	55	62	63	60
20,075	99	81	55	49	55	62	63	60
20,100	99	82	55	49	55	62	64	60
20,125	100	82	55	49	56	62	64	61
20,150	100	82	56	49	56	63	64	61
20,175	100	82	56	49	56	63	64	61
20,200	100	83	56	49	56	63	64	61
20,225	100	83	56	49	56	63	65	61
20,250	100	84	56	49	56	64	65	61
20,275	100	84	57	49	57	64	65	62
20,300	100	85	57	49	57	64	65	62
20,325	100	85	57	49	57	64	65	62
20,350	100	85	57	50	57	64	65	62
20,375	101	85	57	50	57	65	65	62
20,400	101	85	57	50	58	65	66	63
20,425	101	85	57	50	58	65	66	63
20,450	102	86	57	50	58	65	66	63
20,475	102	86	57	50	58	65	67	63
20,500	102	87	58	50	58	65	67	63
20,525	102	88	58	50	59	66	67	63
20,550	102	88	58	50	59	66	67	64
20,575	102	89	58	50	59	66	67	64
20,600	102	89	58	50	60	66	68	64
20,625	102	90	58	50	60	67	68	64
20,650	103	90	59	51	60	67	69	65
20,675	103	90	59	51	60	67	69	65
20,700	103	90	59	51	61	68	69	65
20,725	103	90	59	51	61	68	69	65
20,750	104	90	59	51	61	68	70	65
20,775	104	90	59	51	62	68	70	66
20,800	104	90	60	51	62	68	70	66
20,825	105	90	60	51	62	68	70	66
20,850	105	91	60	51	63	68	70	66
20,875	105	91	60	51	63	68	71	67
20,900	105	91	60	51	64	68	71	67
20,925	105	92	60	51	64	68	71	67
20,950	105	92	60	51	64	68	72	68
20,975	105	93	61	51	64	69	72	68
21,000	105	93	61	52	65	69	73	68
21,025	105	93	61	52	65	69	73	68
21,050	106	94	62	52	65	69	73	69

21,075	106	94	62	52	65	69	74	69
21,100	107	95	63	52	66	69	74	69
21,125	107	95	63	52	66	69	74	69
21,150	107	95	64	52	66	70	75	70
21,175	107	95	64	52	66	70	76	70
21,200	108	96	65	53	66	70	77	70
21,225	108	96	65	53	67	70	77	70
21,250	108	97	65	53	67	70	78	70
21,275	108	97	65	53	67	70	79	71
21,300	108	97	66	53	67	71	79	71
21,325	109	97	66	53	67	71	80	71
21,350	109	98	66	53	68	71	80	71
21,375	109	98	67	53	68	71	80	72
21,400	110	98	67	53	68	72	80	72
21,425	110	98	67	54	68	72	80	73
21,450	110	99	67	54	68	72	80	73
21,475	110	99	67	54	68	72	80	74
21,500	110	99	67	54	68	72	80	74
21,525	111	99	67	55	69	73	80	75
21,550	111	100	68	55	69	73	81	75
21,575	112	100	68	55	69	73	81	75
21,600	112	100	68	55	69	73	82	76
21,625	112	100	68	55	69	73	82	77
21,650	112	100	68	55	69	74	82	77
21,675	112	100	68	55	69	74	83	77
21,700	112	100	69	56	69	74	84	77
21,725	112	101	69	56	69	74	84	77
21,750	112	101	69	56	69	75	85	77
21,775	112	101	70	57	69	75	85	77
21,800	112	102	70	57	69	76	86	77
21,825	112	102	71	57	69	76	87	77
21,850	112	103	71	58	70	76	88	78
21,875	113	103	71	58	70	77	89	79
21,900	113	104	72	58	70	77	90	80
21,925	113	104	72	58	70	77	91	80
21,950	114	105	73	59	71	77	91	80
21,975	114	105	74	59	71	78	92	80
22,000	115	105	74	59	72	78	93	81
22,025	115	105	75	59	73	78	94	82
22,050	115	105	75	59	74	79	95	82
22,075	115	105	76	60	75	79	95	83
22,100	115	105	76	60	75	80	95	84
22,125	115	105	78	60	75	80	96	85
22,150	115	105	79	60	75	80	97	85
22,175	115	105	80	61	75	80	97	85
22,200	115	105	80	61	76	80	97	87
22,225	115	105	81	62	77	80	98	88

22,250	115	105	82	62	78	80	98	90
22,275	115	105	83	62	78	81	99	91
22,300	115	105	84	63	80	81	99	91
22,325	115	106	84	63	80	82	100	93
22,350	116	106	85	63	80	82	100	94
22,375	116	106	85	63	80	83	101	96
22,400	116	107	85	63	80	85	101	96
22,425	116	107	86	64	81	85	103	98
22,450	116	107	87	64	83	86	104	99
22,475	117	108	87	64	85	87	104	99
22,500	117	108	88	64	85	88	105	100
22,525	117	109	88	64	85	88	106	100
22,550	117	109	90	65	86	90	107	100
22,575	117	109	90	65	88	90	107	100
22,600	118	110	90	66	89	91	108	100
22,625	118	110	90	66	90	92	108	101
22,650	118	110	92	66	90	92	109	102
22,675	118	110	94	67	90	93	109	103
22,700	119	110	94	67	90	94	110	104
22,725	119	111	94	67	90	94	110	104
22,750	119	111	94	68	91	94	110	105
22,775	119	112	94	68	92	95	110	106
22,800	120	112	94	68	92	95	111	107
22,825	120	112	94	68	93	96	111	108
22,850	120	113	94	68	94	96	112	109
22,875	120	113	94	68	94	97	112	110
22,900	120	113	94	68	95	97	113	110
22,925	121	114	94	69	95	98	113	111
22,950	121	114	94	69	96	99	113	112
22,975	121	114	94	70	97	100	113	112
23,000	121	115	95	70	97	100	114	113
23,025	121	115	96	70	98	100	114	114
23,050	121	115	98	70	98	100	115	114
23,075	122	115	99	70	99	100	115	114
23,100	122	115	100	70	100	100	115	115
23,125	122	115	100	71	100	100	116	116
23,150	122	115	100	71	100	100	117	116
23,175	123	115	100	72	100	101	117	117
23,200	123	115	100	72	100	102	117	117
23,225	123	115	100	72	100	103	117	118
23,250	123	115	101	73	100	104	117	118
23,275	123	115	101	73	100	105	118	119
23,300	124	115	101	73	100	105	118	119
23,325	124	115	101	74	100	106	118	120
23,350	124	115	101	74	101	107	119	120
23,375	124	115	102	74	101	107	119	120
23,400	124	115	102	75	101	108	119	120

23,425	124	115	103	75	101	108	120	121
23,450	124	115	104	75	102	109	120	121
23,475	125	115	105	75	102	110	120	121
23,500	125	115	105	76	102	110	120	122
23,525	125	115	106	76	102	111	120	122
23,550	125	116	106	77	103	111	120	122
23,575	125	116	106	78	105	112	120	123
23,600	125	116	107	79	105	112	121	123
23,625	125	116	107	80	105	112	121	123
23,650	125	116	107	80	106	113	121	124
23,675	126	117	107	80	106	113	121	124
23,700	126	117	108	80	107	113	122	124
23,725	126	117	109	80	107	114	122	125
23,750	126	117	110	80	107	114	122	125
23,775	126	117	110	80	109	114	123	125
23,800	127	117	110	80	109	115	123	125
23,825	127	118	111	80	109	115	123	125
23,850	127	118	112	80	110	115	124	126
23,875	127	118	112	80	110	115	124	126
23,900	127	118	112	80	110	115	125	126
23,925	127	118	113	80	111	115	125	126
23,950	128	119	113	80	111	115	125	127
23,975	128	119	114	80	112	115	125	127
24,000	128	119	114	80	112	115	125	127
24,025	128	119	115	80	112	115	125	128
24,050	128	119	115	81	113	115	125	128
24,075	128	119	115	84	113	115	126	128
24,100	129	119	115	85	114	115	126	129
24,125	129	119	115	87	114	115	126	129
24,150	129	120	115	88	115	115	127	129
24,175	129	120	115	90	115	115	127	130
24,200	129	120	115	90	115	116	127	130
24,225	130	120	115	91	115	116	127	130
24,250	130	120	115	93	115	116	128	130
24,275	130	120	115	94	115	116	128	130
24,300	130	121	115	95	115	117	128	130
24,325	130	121	115	95	115	117	129	131
24,350	130	121	115	96	115	118	129	131
24,375	130	121	115	97	115	118	129	131
24,400	130	121	115	97	115	118	129	132
24,425	131	121	115	98	115	118	130	132
24,450	131	121	115	98	115	119	130	132
24,475	131	121	115	100	115	119	130	132
24,500	131	122	115	100	115	119	131	133
24,525	131	122	116	102	115	119	131	134
24,550	131	122	116	102	115	120	131	134
24,575	131	122	116	103	115	120	132	134

24,600	131	122	117	103	115	120	132	135
24,625	132	122	117	103	116	120	133	135
24,650	132	123	117	104	116	120	133	135
24,675	132	123	118	104	116	120	134	135
24,700	132	123	119	105	116	120	134	136
24,725	132	123	119	107	117	120	135	136
24,750	132	123	120	107	117	121	135	136
24,775	132	123	120	107	118	121	135	137
24,800	133	123	120	107	118	121	136	137
24,825	133	124	120	108	119	121	137	138
24,850	133	124	121	108	119	122	137	139
24,875	133	124	121	110	119	122	138	139
24,900	134	124	121	110	120	122	138	140
24,925	134	124	121	111	120	122	139	140
24,950	134	124	122	111	120	123	139	140
24,975	134	124	122	112	120	123	140	141
25,000	134	124	122	113	121	123	140	141
25,025	134	125	122	114	121	123	141	142
25,050	135	125	122	114	121	124	141	142
25,075	135	125	123	115	121	124	141	143
25,100	135	125	123	115	122	124	142	143
25,125	135	125	123	115	122	124	143	144
25,150	135	125	123	115	122	124	143	144
25,175	135	125	124	115	123	125	143	145
25,200	135	125	124	115	123	125	144	145
25,225	135	126	124	115	123	125	144	146
25,250	135	126	124	115	124	125	145	146
25,275	135	126	125	115	124	125	145	147
25,300	135	126	125	115	124	125	146	147
25,325	135	126	125	115	124	126	146	147
25,350	135	126	125	115	125	126	147	148
25,375	135	127	125	115	125	126	147	148
25,400	135	127	125	115	125	126	147	148
25,425	135	127	126	115	126	127	147	149
25,450	136	127	126	115	126	127	147	150
25,475	136	127	126	115	126	127	147	150
25,500	136	127	126	116	127	128	148	150
25,525	136	127	127	117	127	128	149	151
25,550	136	127	127	117	128	128	149	151
25,575	137	128	127	118	128	129	149	152
25,600	137	128	127	119	129	130	150	153
25,625	137	128	128	119	129	130	150	154
25,650	137	128	128	119	129	131	150	154
25,675	137	128	128	120	130	131	150	154
25,700	137	129	128	120	130	132	150	155
25,725	137	129	128	121	130	132	150	155
25,750	137	129	128	121	130	133	150	155

25,775	138	129	128	122	130	133	151	155
25,800	138	129	129	122	131	134	151	155
25,825	138	130	129	123	131	134	151	155
25,850	139	130	129	123	131	135	152	155
25,875	139	130	129	124	132	135	153	155
25,900	139	130	129	124	132	136	153	155
25,925	139	130	129	125	132	136	153	155
25,950	139	131	130	125	132	137	154	155
25,975	140	131	130	125	133	137	154	155
26,000	140	131	130	125	133	138	155	155
26,025	140	131	130	126	133	138	155	155
26,050	140	132	130	126	134	138	155	155
26,075	140	132	130	126	134	139	155	155
26,100	141	132	130	127	134	139	155	155
26,125	141	132	131	127	135	139	155	155
26,150	141	133	131	127	135	139	155	155
26,175	141	133	131	128	135	139	155	156
26,200	142	133	131	128	135	139	155	156
26,225	142	133	131	128	135	139	155	157
26,250	142	134	131	128	135	139	155	157
26,275	142	134	132	128	135	139	155	158
26,300	143	135	132	129	135	139	155	158
26,325	143	135	132	129	135	139	155	158
26,350	143	135	132	129	135	139	155	159
26,375	144	135	132	130	135	139	156	160
26,400	145	135	133	130	135	139	156	160
26,425	145	135	133	131	135	139	157	161
26,450	145	135	133	131	136	139	158	161
26,475	145	135	133	131	136	140	159	162
26,500	146	135	134	132	136	140	161	162
26,525	147	135	134	132	137	141	164	163
26,550	147	135	134	132	137	141	168	164
26,575	147	135	135	132	137	142	170	164
26,600	147	135	135	132	137	142	170	165
26,625	147	136	135	132	137	143	171	165
26,650	147	136	135	132	137	143	171	168
26,675	148	136	135	133	137	144	172	169
26,700	148	137	135	133	138	145	173	170
26,725	149	137	135	133	138	145	174	172
26,750	149	137	135	133	139	146	175	175
26,775	150	137	135	133	139	146	175	175
26,800	150	137	135	133	139	147	175	175
26,825	150	137	135	133	140	147	175	175
26,850	150	137	135	134	140	148	175	176
26,875	150	137	136	134	141	148	175	178
26,900	150	137	137	134	141	149	176	179
26,925	151	137	137	134	142	149	177	180

26,950	151	138	137	134	142	150	179	180
26,975	151	138	137	134	143	150	179	181
27,000	152	139	137	134	143	150	180	182
27,025	153	139	137	135	144	150	180	182
27,050	153	139	137	135	145	150	180	184
27,075	153	140	137	135	146	151	181	185
27,100	153	140	137	135	146	151	181	185
27,125	153	140	138	135	147	151	182	188
27,150	154	141	138	135	147	152	183	189
27,175	154	141	139	135	147	152	184	190
27,200	154	142	140	135	148	153	185	191
27,225	154	142	140	135	149	153	185	192
27,250	154	142	141	135	149	154	186	193
27,275	155	143	141	135	150	154	189	195
27,300	155	143	142	135	150	154	190	196
27,325	156	143	142	135	150	155	192	200
27,350	156	144	143	136	150	155	193	200
27,375	156	144	144	136	150	156	194	200
27,400	156	144	144	136	150	156	195	202
27,425	156	145	144	137	151	157	196	203
27,450	156	145	144	137	151	157	200	205
27,475	156	145	145	137	151	158	200	206
27,500	157	146	145	137	152	159	200	208
27,525	158	146	145	137	153	160	200	210
27,550	158	147	146	137	154	160	200	214
27,575	158	147	146	137	155	161	201	217
27,600	158	147	146	137	156	162	203	220
27,625	158	147	146	137	157	164	204	223
27,650	159	148	147	137	158	168	205	225
27,675	160	148	147	138	159	175	207	225
27,700	160	148	147	138	159	175	208	225
27,725	161	149	147	138	160	175	213	225
27,750	162	149	148	138	161	175	220	225
27,775	162	149	148	139	161	176	220	230
27,800	164	150	148	139	163	178	220	230
27,825	166	150	148	139	163	180	220	239
27,850	166	150	148	140	164	180	221	240
27,875	167	150	149	140	166	181	225	240
27,900	167	151	149	141	167	182	225	240
27,925	168	151	149	142	168	182	225	240
27,950	170	152	150	142	170	183	225	240
27,975	171	152	150	142	171	185	225	240
28,000	172	153	150	143	172	187	225	240
28,025	174	153	150	143	175	188	230	240
28,050	175	154	150	145	175	189	230	240
28,075	175	154	151	145	175	191	230	240
28,100	175	154	151	146	175	192	231	240

28,125	176	154	152	146	176	192	235	240
28,150	177	154	152	147	177	194	239	240
28,175	178	155	153	148	180	197	240	240
28,200	179	156	153	148	180	200	240	240
28,225	180	156	153	149	182	200	240	241
28,250	181	156	154	149	184	200	240	242
28,275	181	156	154	149	187	200	240	243
28,300	184	156	154	149	188	200	240	244
28,325	186	158	154	150	190	200	240	247
28,350	188.2	158	154.36	150	193.62	200	240	247.75
28,375	189.39	158	156	150	194.94	200	240	249.34
28,400	191.44	158	156	150	196.96	200	241.38	250
28425	193.37	158	156	150.21	199.35	201.26	242.59	250
28450	195.29	158.02	156	150.4	200	203.32	243.91	250
28475	196.91	160.9	156	151.09	200	205.11	245.02	250
28500	197.9	161.89	158	151.29	200	206.64	246.43	251.11
28525	198.57	165	158	151.56	200	209.18	246.97	252.91
28550	200	165.8	158	151.72	200	211.63	247.53	255
28575	200	166.66	158	152.09	200	213.08	248.2	255
28600	200	170	158	152.39	200	219.2	248.73	257.8
28625	200	170	159.64	152.69	200.53	221.55	250	258.88
28650	200	173.99	160.68	153	203.64	224.52	250	260
28675	200	175	163.18	153.29	206.52	224.52	250	260
28700	200.24	175	165.98	153.7	207.47	224.52	250	261.42
28725	200.24	177.8	166.82	153.99	207.96	224.52	250	264
28750	200.24	178.42	170	154.35	208.79	224.52	250	268
28775	202.82	178.64	172.62	154.89	209.47	225	250.93	273.74
28800	205	179.79	175	155.07	212.8	225	254.48	275
28825	206.27	180.9	176	155.49	216.41	225	255	278
28850	206.86	181	181.04	155.95	220	225	257.51	280
28875	208.22	182.98	185	156.1	223.87	230	261.94	283.54
28900	210.31	185	188.14	156.35	224.52	230	261.94	287.73
28925	210.4	187.04	188.65	156.67	224.52	230	264	294.41
28950	210.87	188.62	190	157.23	224.52	230	267.61	294.41
28975	215.14	190	190.02	157.91	224.52	230	271.17	298.63
29000	216	190.95	193.69	158.29	225	230	275	300
29025	216	192.91	195.38	158.55	225	230	277	300
29050	217.01	194.9	197.99	159.87	227.79	240	281	
29075	218.09	195	199.43	160.36	230	241.38	285.44	
29100	218.98	195.83	200	161.37	230	242.64	292	
29125	220	197.41	200	162.19	231.58	244.89	294.41	
29150	224.86	200	200	163.72	233.37	247	294.41	
29175	227.03	200	200	165.79	234.12	248.22	300	
29200	229.76	200	200	169.17	236.57	249.45	300	
29225	230.21	200	200.42	170	239.16	250	300	
29250	230.65	200	206.22	171.94	240.61	250		
29275	232.67	200	209.03	175	240.67	250		

29300	234.47	200.05	209.99	175	240.67	250		
29325	235.56	200.24	210.57	179.79	242.14	250		
29350	237.6	200.24	211.31	188.2	245.25	250		
29375	238.08	200.24	212.31	190	246.76	250		
29400	240	200.24	213.35	195	249.57	250.6		
29425	240.67	201.22	216	199.74	250	252.54		
29450	240.67	202.82	216	200	250	254		
29475	240.67	204.19	217.81	200.05	250	255		
29500	240.67	206.42	220	202.96	250	255.82		
29525	240.67	207.18	225.03	206	250	257.57		
29550	240.67	208.29	229.07	207	250	259.2		
29575	242.62	210	233.97	207.78	250	261.94		
29600	244.94	213.64	239.12	210	250	261.94		
29625	246.05	216	240.67	213.71	250.1	261.94		
29650	248.72	216	240.67	216.94	251.78	264		
29675	250	217.3	240.67	220	252.53	265.73		
29700	250	220	240.67	220.3	254	267		
29725	250	220.94	240.67	221.46	255.92	270		
29750	250	225.11	240.67	222.35	257.8	274		
29775	250	227.6	240.67	222.93	261.51	275		
29800	250	229.43	245.28	223.21	265	275		
29825	250	230.84	246.3	226.59	266	275		
29850	250.15	231.95	247.22	233.37	267.2	278.14		
29875	251.55	233.58	248.69	237.44	267.2	280		
29900	253.34	234.38	249.62	240.67	267.38	282		
29925	254	235.46	250	240.67	269.38	285		
29950	254.05	236.67	250	240.67	270.84	288.47		
29975	256.11	237.6	250	240.67	272.74	294.41		
30000	256.11	238.85	250	240.67	275	294.41		
30025	257.86	240	250	240.67	275	298		
30050	260	240.67	250	240.67	275	300		
30075	261.99	240.67	250	241.51	276.36	300		
30100	262.61	240.67	250.49	249.11	279	300		
30125	264	240.67	250.85	250	280.5	300		
30150	265	240.67	251.41	250	281.17	300		
30175	266.15	240.67	252.55	250	284	300		
30200	270	240.67	253.3	250	285			
30225	273.18	242.27	253.97	250	294.41			
30250	277	243.62	254.23	250	294.41			
30275	279.12	244.83	254.91	250	295			
30300	280.92	245.76	256	250	299			
30325	282.99	247.24	256.11	252.94	300			
30350	285.97	248.9	256.11	256	300			
30375	286.44	250	256.91	256.11	300			
30400	286.8	250	261.52	256.11	300			
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30450	287.91	250	271.81	260.46				

30475	288.22	250	275.3	261.59					
30500	290	250	278	262.57					
30525	291.1	250	278	263.71					
30550	291.95	250	280	264.57					
30575	291.99	251.35	280	265.32					
30600	292.13	252.21	282	266					
30625	292.7	254	282	266.69					
30650	293.34	255.26	284	267.63					
30675	294	256.11	284	268.8					
30700	294.41	256.11	292.09	269.55					
30725	294.41	259.97	294.41	270.46					
30750	296	264	294.41	275.97					
30775	303	264	310	279.18					
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Exhibit C to Attachment 5

Analysis and Assessment of Baseline Accuracy

Final Report

ISO-NE, Holyoke, Massachusetts, August 4, 2011

Table of Contents

List of Exhibits:

1. Executive Summary

The purpose of this report is to describe the analysis and assessment performed by KEMA for ISO New England ("ISO-NE"). ISO-NE engaged KEMA to assist in developing methods and techniques to assess the accuracy of customer baselines in compliance with the order issued by the Federal Energy Regulatory Commission ("Commission") on March 15, 2011 concerning demand response compensation in organized wholesale energy markets administered by a Regional Transmission Organization ("RTO") or an Independent System Operator ("ISO").[1]

This report examines the issues around baseline accuracy and investigates changes to the current ISO-NE 90/10 baseline calculation method ("ISO-NE 90/10")[2] designed to improve accuracy and decrease bias. An inaccurate, biased baseline prevents accurate measurement of demand response performance, which is a requirement of the Final Rule.[3]

Based on the Commission's net benefits test, Demand Reduction Threshold Prices are likely to be so low such that demand reduction offers at the threshold price would clear the energy market essentially every day in all zones. This is problematic because current baseline rules exclude meter data on event days from the baseline calculation. Continuous event days cause the accuracy of the baseline to degrade over time because there is little or no recent data to refresh the baseline. Consequently baselines can become "stuck", that is, based on old data that does not provide an accurate estimate of current load consumption patterns.

This analysis assessed baseline accuracy by measuring bias or systematic error. Error is calculated as (Baseline) – (Actual Load). A positive error means the baseline is over-estimating actual load and the calculated load reduction amounts would be overstated. A negative error means the baseline is under-estimating actual load and the calculated load

[1] Demand Response Compensation in Organized Wholesale Energy Markets, Final Rule, 134 FERC ¶ 61,187, Order No. 745, Docket No. RM10-17-000 (March 15, 2011) (the "Final Rule").

[2] The ISO-NE 90/10 is effectively a 10-day rolling average of interval meter data from days on which no events have occurred. Currently the initial baseline is a 5-day average of the metered load. The baseline for each day going forward is calculated as .90 times the baseline from the previous day plus .10 of the meter data for the current day.

[3] "If necessary, each RTO and ISO should propose any changes needed to ensure that measurement and verification of demand response will adequately capture the performance (or non-performance) of each participating demand response market participant to be consistent with the requirements of this Final Rule." Final Rule at 94.

reduction amounts would be understated. In this report, the average median bias and average median relative error are used interchangeably to define the amount of systematic error observed across a period of time (typically the four months from September through December 2010).

The baseline analysis was performed in multiple parts. First, the impact of the start date – i.e., the day a demand response asset commences submitting demand reduction offers – on structural bias was evaluated by using two scenarios: when the baseline is refreshed daily, (no clearing occurs on any day) and when the baseline is never refreshed with contemporary data (clearing occurs on every day).[4] The results of these scenarios show that the average median bias remains relatively small and ranges from -0.1% to 3.0% when the baseline is refreshed daily. This small bias is caused by the inherent lag in the 90/10 baseline methodology where historical data is given more weight (i.e., 90%) than data from the most recent day (i.e., 10%) when calculating the baseline. In the case when the baseline is never refreshed, the bias in both directions is larger (indicating more variance) and ranges from -7.9% to 17%. In this situation, the bias in the baseline is primarily due to the infrequent inclusion of recent meter data in the baseline calculation. The highest observed bias of 17% occurred when a September 1, 2010 start date was used. This start date was used for the additional analysis because it was the period of the highest bias and constitutes the period of greatest concern with respect to maintaining baseline accuracy.

Next, a simulation of three baseline methodologies was run assuming a start date of September 1, 2010 and assuming that participants offered at the monthly Demand Reduction Threshold Price based on the Commission's net benefits test. All three methodologies are based on ISO-NE 90/10 but differ in terms of the way the baseline is adjusted to account for day-to-day variations (e.g., unusually high temperatures during a heat wave). The baseline adjustment is computed as the average difference between the metered load and baseline in the two-hour period beginning 2.5 hours prior to the start of the first demand reduction interval in the day. This average difference is added to the baseline in each interval of the day. The resulting adjusted baseline is used to determine performance. An asymmetric baseline adjustment is one in which the baseline adjustment is made in only one direction (that is, to raise the expected consumption level for that interval). A symmetric adjustment adjusts the baseline in either an upward or a downward direction as appropriate. The case where no baseline adjustment is added to the baseline was also included in the analysis.

[4] The ISO-NE 90/10 baseline with no adjustment was used in both scenarios.

Offers were cleared based on actual 2010 Locational Marginal Prices ("LMPs"). Monthly Demand Reduction Threshold Prices ("DRTPs"), were developed for ISO-NE by Charles River Associates ("CRA") and were provided to KEMA. Baseline accuracy was assessed for these three methodologies:

1. ISO-NE 90/10 with Asymmetric Adjustment (current ISO-NE method)
2. ISO-NE 90/10 with No Adjustment
3. ISO-NE 90/10 with Symmetric Adjustment

All of the baseline variations tested had more than 10% of positive bias, which means that demand response resource actual performance would be overstated by more than 10%. The source of the bias is due to consecutive event days causing the baseline to be fixed at a high usage level that becomes less accurate over time. The highest average relative error was 18.1% for the current ISO-NE Baseline method ("ISO-NE 90/10 with Asymmetric Adjustment"). The ISO-NE 90/10 with Symmetric Adjustment had the lowest average relative error of 10.4%, had the least bias and was the most accurate of the three variants tested.

To improve baseline accuracy further, a mechanism is needed that refreshes the baseline with current data to maintain baseline accuracy without restricting the participant's ability to offer and clear cost effective demand response.

The third part of the analysis evaluated two baseline refreshment mechanisms. The first, a Baseline Accuracy Price ("BAP"), uses price as determinant for whether or not days should be included in the baseline calculation. Offer prices and LMPs are compared to the BAP. If the offer clears and the LMP in the cleared intervals is greater than the BAP then the actual metered load data for that day would not be used in the baseline calculation. However, if the offer cleared and the LMP in the cleared intervals is less than or equal to the BAP then the actual metered load data for that day would be included in the baseline calculation. The BAP would be established to make certain that a sufficient number of days of actual metered load data are used in the baseline calculation to ensure the baseline remains accurate and unbiased. The BAP was incorporated into the three baseline variations used in the baseline methodology simulations with the same clearing assumptions. The ISO-NE 90/10 with Symmetric Adjustment methodology using the BAP was the best performer with an average relative error of 4.7%, which is a significant improvement over the 10.4% in the previous simulation.

An alternative baseline refreshment approach, called “X of Last 10 Days”, uses an administrative rule for including days in the baseline computation. This approach requires X number of the last 10 days be included in the baseline calculation. The “X of Last 10 Days” method was evaluated using the same three baseline variations during the same time-period with the same clearing assumptions as the BAP simulations. The “X of Last 10 Days” method was tested using values for X of one to five days as the required refreshment rate. The ISO-NE 90/10 with Symmetric Adjustment methodology was also the best performer using this method. The closest result to the BAP simulation is when X = 3, where the average relative error is 4.0%.

Initially, the baseline adjustment calculation (which determines the factor to be added to the baseline) was performed using a simplified version of the current ISO-NE baseline adjustment (“ISO-NE standard adjustment”). The simplified approach did not apply any adjustment on days where the first interruption occurred in any of the first three hours of the day. As a final step, all scenarios were run again using the ISO-NE standard adjustment calculation which uses the two-hour period starting two and one half hours prior to the start of the first interruption in the day regardless of whether or not that interruption is in the first three hours of the day. As a result of this change the ISO-NE 90/10 baseline with Symmetric Adjustment and BAP method improved from 4.7% bias to 2.9% and the ISO-NE 90/10 baseline with Symmetric Adjustment and the ”3 of the Last 10 Days” method improved from 4.0% bias to 2.7% bias. The ISO-NE 90/10 with Symmetric Adjustment was the best performer of the three baseline methodologies.

The results of the analysis indicate a serious potential problem with the accuracy of the current ISO-NE 90/10 with Asymmetric Adjustment. Accuracy would be significantly improved by using the ISO-NE 90/10 with Symmetric Adjustment. This finding is supported by an extensive baseline accuracy study conducted by KEMA for PJM earlier in 2011 entitled “PJM Empirical Analysis of Demand Response Baseline Methods”. The PJM study evaluated the accuracy of twelve baseline methods using two years of load data from about 20,500 C&I customers in the PJM service territory including over 4,500 emergency and economic demand response participants. The ISO-NE 90/10 was included as part of the study and was evaluated in terms of accuracy, bias and variability when used in two forms: with No Adjustment and with a Symmetric Adjustment. The ISO-NE 90-/10 with a Symmetric Adjustment was one of the top performers under all three evaluation criteria. It is important to note that the current ISO-NE baseline adjustment method, ISO-NE 90/10 with Asymmetric Adjustment was **<u>not</u>** included in the study. The Asymmetric Adjustment method was purposely omitted from the PJM study, because the project sponsors and analysts felt that this method was a significant source of bias and not worth including in the comprehensive study.

The bias in the ISO-NE 90/10 with Asymmetric Adjustment is clearly demonstrated when used with the DRTPs at which price demand response would clear the energy market on most days of the year. To improve the accuracy of the baseline and measurement of performance calculations, KEMA recommends that ISO-NE implement the following changes:

- Change the baseline adjustment method from Asymmetric to Symmetric.
- Utilize the "X of Last 10 Days" baseline refreshment mechanism with X=3.
- Continue to use the current baseline adjustment calculation, the ISO-NE standard adjustment.

2. Introduction

ISO-NE engaged KEMA to assist in developing methods and techniques to assess the accuracy of customer baselines in compliance with the Commission's order in 'Demand Response Compensation in Organized Wholesale Energy Markets' Docket No. RM10-17-000, Order No. 745. This report provides an assessment of alternative baseline methodologies and baseline refreshment mechanisms designed to address baseline accuracy issues that can emerge in the ISO-NE's Energy Market as a result of FERC Order 745.

2.1 Background

On March 15, 2011, the Commission issued a final rule in Docket RM10-17-000 (130 FERC ¶ 61,213, Order No. 745). This docket began with the issuance of a Notice of Proposed Rulemaking ("NOPR") about a year ago on March 18, 2010 (134 FERC ¶ 61,187). The NOPR that was initially issued proposed that ISOs and RTOs be required to compensate demand response providers at the full LMP for demand reductions made in response to price signals in all hours where demand response resources reduce energy consumption from expected levels. Further, the Commission issued a Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference ("Supplemental NOPR") on August 2, 2010.[5] The Supplemental NOPR sought additional comment on: whether the Commission should adopt a net benefits test for determining when to compensate demand response providers, and, if so, what, if any, requirements should apply to the methods for determining net benefits; and what, if any, requirements should apply to how the costs of demand response are allocated. Commission Staff held a technical conference focused on these two issues on September 13, 2010.[6]

In the Final Rule issued March 15, 2011, the Commission stated that demand response resources should be compensated for reductions they bid into the energy market at the full LMP provided that the dispatch of these resources satisfies a "net benefits test."[7] One of the

[5] Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference, 75 FR 47499 (Aug. 6, 2010), 132 FERC ¶ 61,094 (2010) (Supplemental NOPR).
[6] See Notice of Technical Conference (Aug. 27, 2010).
[7] Final Rule at PP 48, 54.

major differences between the NOPR and the Final Rule is that the Final Rule limits when demand response will be paid for participating in the energy market. Unlike the NOPR, which called for payments for demand response in all hours – the Final Rule limits payment to times when a net benefit test is satisfied. The purpose of the net benefits test is to "ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching those resources".[8] As part of the net benefit test requirement, the final rule requires ISOs and RTOs to "determine on a monthly basis under which conditions it is cost-effective to pay full LMP to demand resources."[9]

ISO-NE contracted with CRA to calculate monthly prices that satisfy the net benefits test. CRA developed monthly DRTPs based on the net benefits test described in the Final Rule using 2010 historical data and supply curves. On average the monthly DRTPs developed by CRA are about $40.

DRTPs in 2010 at these levels would have resulted in a clearing frequency that is similar to that experienced in 2007, when the Day-Ahead Load Response Program ("DALRP") had a fixed minimum offer level of $50/MWh. At that time, the $50/MWh minimum offer level facilitated strategic behavior that permitted DALRP participants to exaggerate load reductions from their demand response assets. This behavior resulted in payments for "phantom," rather than actual, load reductions. If left unchecked, DALRP participants could have been paid millions of dollars in energy payments for non-existent load reductions, which would undermine the integrity of the New England demand response programs.

The strategic behavior experienced in the DALRP was that, beginning in August 2007, a large number of assets were offering load reductions every day at the minimum bid price, then $50/MWh. Market prices rose substantially from the time the $50 minimum was established, and these assets were clearing every day. Because meter data on cleared days is excluded from the calculation of the Customer Baseline, an asset that cleared every day had a "static" baseline that did not change to reflect the seasonal changes in the customer's usage patterns.

[8] Final Rule at P 53.

[9] Final Rule at P 79.

As described in the Yoshimura testimony accompanying the ISO's February 5, 2008 filing with the FERC in ISO New England Inc., Docket No. ER08-538-000; Filing of Changes to Day-Ahead Load Response Program; Expedited Comment Period and Consideration Requested:

> With the minimum DALRP offer price so low compared with typical day-ahead LMP prices, a DALRP program participant with a load profile that is typically higher in the summer than the winter can forego offering into the program for ten days, establish a high Customer Baseline during those days, and then maintain that baseline by submitting a minimum DALRP offer for every weekday thereafter and be very confident that it would clear in DALRP every such weekday. The high, static baseline thereby created (through evasion of dynamic baseline adjustment through constant DALRP offer clearance) would produce consistent "phantom reductions" for purposes of the DALRP during the non-summer periods, even though the customer is taking no action to reduce its usual consumption levels.

This report examines the issues around baseline accuracy and analyzes potential changes to the current ISO-NE baseline calculation method designed to improve accuracy and decrease bias. An accurate baseline will result in accurate measurement of demand response performance

2.2 Baseline Accuracy Analysis

The current baseline calculation method, ISO-NE 90/10, is effectively a 10-day rolling average of interval meter data from days on which no events have occurred. Currently the initial baseline is a 5-day average of the metered load. The baseline for each day going forward is calculated as .90 times the baseline from the previous day plus .10 of the meter data for the current day. The baseline is adjusted to account for conditions on event days (e.g., unusually high temperatures during a heat wave). The baseline adjustment is computed as the average difference between the metered load and baseline in the two-hour period beginning 2.5 hours prior to the start of the first demand reduction interval in the day. This average difference is added to the baseline in each interval. The resulting adjusted baseline is used to determine performance. In this report three adjustment methods are analyzed:

- No adjustment is added to the baseline.

- An asymmetric baseline adjustment, one in which the baseline adjustment is made in only one direction (that is, to raise the expected consumption level for that interval) is added to the baseline.

- A symmetric adjustment that adjusts the baseline in either an upward or a downward direction as appropriate is added to the baseline.

In 2011, KEMA conducted an extensive baseline accuracy study for PJM entitled "PJM Empirical Analysis of Demand Response Baseline Methods". This study evaluated the accuracy of twelve baseline methods using two years of load data from about 20,500 C&I customers in the PJM service territory including over 4,500 emergency and economic demand response participants. The ISO-NE 90/10 was included as part of the study and was evaluated in terms of accuracy, bias and variability when used in two forms: without an adjustment and with a Symmetric Adjustment. The ISO-NE 90/10 with a Symmetric Adjustment was one of the top performers under all three evaluation criteria. It is important to note that the current ISO-NE baseline adjustment method, ISO-NE 90/10 with Asymmetric Adjustment was **not** included in the study. The Asymmetric Adjustment method was purposely omitted from the PJM study, because the project sponsors and analysts felt that this method was a significant source of bias and not worth including in this comprehensive study. However, since the ISO-NE 90/10 with Asymmetric Adjustment is the method currently used by ISO-NE this methodology is included in the analysis performed for ISO-NE.

The data used for the ISO-NE baseline accuracy analysis were actual hourly loads for a set of customers (assets) that *did not* participate in the DALRP or Real-Time Price Response Program.[10] These data were from calendar year 2010. ISO-NE provided hourly data from non-participant commercial and industrial customers (assets).

The analysis of baseline accuracy was performed as follows:

[10] The dataset provided by ISO-NE contained flags that indicated when an asset participated in an event so those participants could be removed from the analysis. There was one event on June 24, 2010 and that day was removed from the analysis. Additionally, there were several audit event days that were also excluded from the analysis.

1. Assess the impact of the start date of participation on the accuracy of the calculated baseline under conditions where demand response assets are clearing every day. In this simulation, no baseline adjustment is used.

2. Examine the accuracy of the ISO-NE 90/10 baseline using three different adjustment methods.

3. Evaluate the impact of incorporating a mechanism to ensure contemporary data is included in the baseline calculation. This part of the analysis looked at the impact on baseline accuracy during a period of consecutive events when a baseline refreshment mechanism was used to include current data in the baseline calculation.

The analysis for ISO-NE assessed baseline accuracy by measuring bias or systematic error. Error is calculated as (Baseline) – (Actual Load). A positive error means the baseline is over-estimating actual load and calculated load reduction amounts would be overstated. A negative error means the baseline is under-estimating actual load and calculated load reduction amounts would be understated. For the main analysis conducted, we calculated each asset's relative error on an hourly basis as the primary measure of baseline accuracy. Daily, asset-level relative error = (mean asset error)/(mean asset actual load). By translating the individual asset errors into relative errors, we can compare and aggregate results across assets of varying sizes. The **median relative error** for a day is the median over all 600+ assets of their daily relative errors. That is, half of the assets had a daily relative error greater than this value and half had a daily relative error below this value for that day.

The median relative error measures **bias** or **systematic error**. That is, the median relative error indicates the systematic tendency of the baseline method to over- or under-state actual load. In this report, the average median bias and average median relative error are used interchangeably to define the amount of systematic error observed across a period of time (typically four months September through December 2010).

2.2.1 Impact of Start Date on Structural Bias

The first analysis performed by KEMA was to evaluate the impact of start date[11] on the structural bias that occurs in the ISO-NE 90/10 baseline with No Adjustment under the following scenarios:

- When the baseline is refreshed daily ("Never Clears")
- When the baseline is not refreshed ("Always Clears")

As shown in Table 1 when the baseline is refreshed daily (Never Clears), the average median bias remains relatively small and ranges from -0.1% to 3.0%. This bias is caused by the inherent lag in the 90/10 baseline methodology where historical data is given more weight (i.e., 90%) than data from the most recent day (i.e., 10%) when calculating the baseline.

Table 1: Average Relative Error in Baseline due to Start Date

	Average Relative Error	
Start Date	Never Clears	Always Clears
1-Jan-10	-0.1%	-2.1%
1-Jun-10	-0.1%	-7.9%
1-Aug-10	3.0%	12.3%
1-Sep-10	2.9%	17.0%
1-Oct-10	2.6%	14.0%

When the baseline is never refreshed (Always Clears), the bias in both directions is larger (indicating more variance) and ranges from -7.9% to 17%. In this situation, the bias in the baseline is due to the lack of contemporary data in the baseline calculations. The highest observed bias of 17% occurred when a September 1, 2010 start date was assumed. A September 1 start date was used for all additional analysis because it was the period of the highest bias and constitutes the period of greatest concern with respect to maintaining baseline accuracy.

[11] Start date is the day a demand response asset begins submitting demand reduction offers.

2.2.2 Simulation of Baseline Variants

A simulation of three ISO-NE 90/10 variations was run assuming a start date of September 1, 2010. Participants were assumed to offer at the DRTP. Offers were assumed to clear in hours where the DRTP was less than or equal to the 2010 LMP.

The accuracy of three variations of the ISO-NE 90/10 was assessed, including:

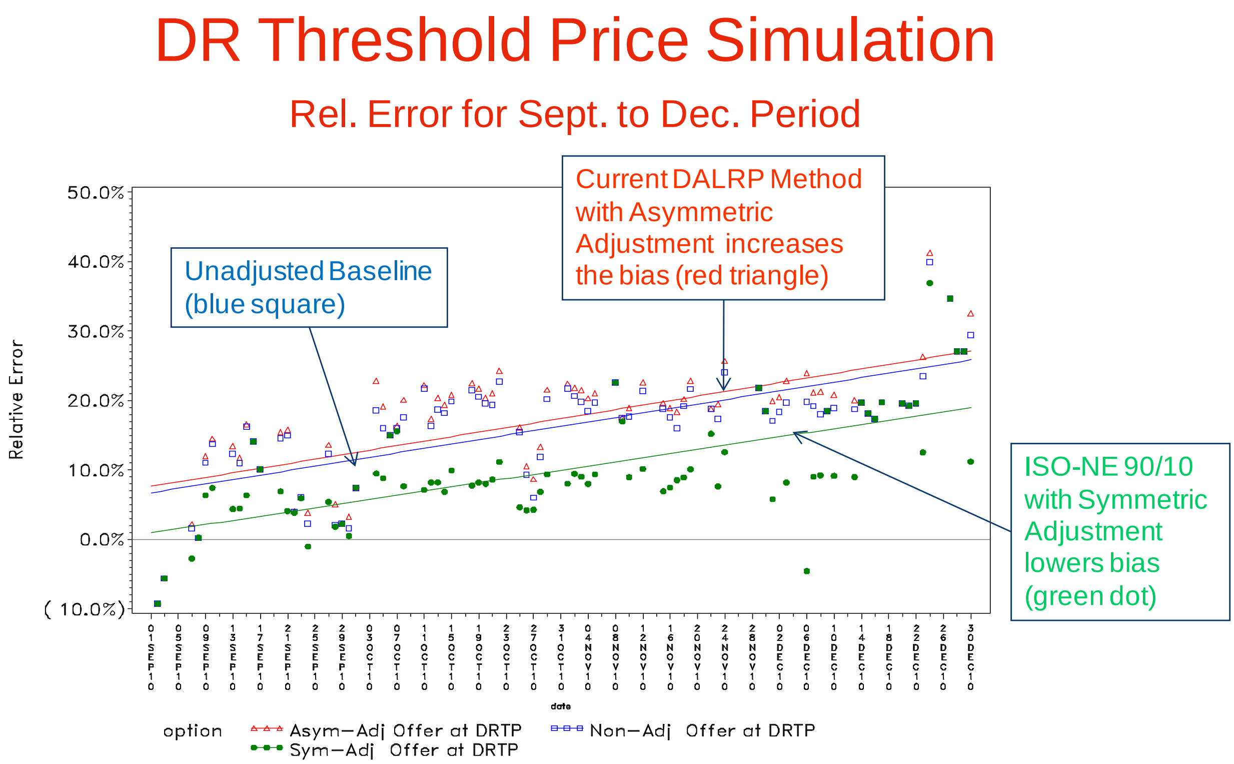
1. ISO-NE 90/10 with Asymmetric Adjustment (current ISO-NE method)
2. ISO-NE 90/10 with No Adjustment
3. ISO-NE 90/10 with Symmetric Adjustment

The ISO-NE 90/10 with Asymmetric Adjustment was included in this study because it is the current method for calculating the baseline. The last two baseline variations were both included in the PJM study and the ISO-NE 90/10 with Symmetric Adjustment was the best performer of the two baseline variations, and was one of the best overall performers in terms of accuracy, bias and variability evaluated in the study.[12]

Figure 1 provides a graphical representation of the results that clearly indicate that the ISO-NE 90/10 with Symmetric Adjustment had the lowest relative error and therefore had the least bias and was the most accurate of the three variants tested.

[12] The baseline referred to in the PJM report as 6-ISONE with Additive Adjustment would be the same as the ISO-NE 90/10 with Symmetric Adjustment in this report and 6-ISONE Unadjusted Baseline would be the same as ISO-NE 90/10 with No Adjustment. ISO-NE 90/10 with Asymmetric Adjustment method was purposely omitted from the PJM study, because the project sponsors and analysts felt that this method was a significant source of bias and not worth including in this comprehensive study.

Figure 1: Relative Error Comparison Bids at DRTP



Each of the baseline variations tested had greater than 10% positive bias, which means that the demand reduction would be overstated by more than 10%. The highest average relative error was 18.1% for the current ISO-NE Baseline method (ISO-NE 90/10 Baseline with Asymmetric Adjustment). The ISO-NE 90/10 with Symmetric Adjustment had the lowest average relative error of 10.4% during the time period September 1 - December 31, 2010. This bias is due to many consecutive event days, which cause the baseline to be fixed at a high summer usage level that becomes less accurate over time. The solution to this problem is to develop a mechanism that refreshes the baseline with current data to maintain baseline accuracy without restricting the participant's ability to offer and clear cost effective demand response.

2.2.3 Baseline Refreshment Mechanisms

Two baseline refreshment mechanisms were evaluated. The first, the Baseline Accuracy Price ("BAP") method, used price as determinant for whether or not days should be included in the baseline calculation. The second baseline refreshment mechanism, called "X of Last 10 Days", uses an administrative rule for inclusion of days in the baseline and requires X number of the last 10 days be included in the baseline calculation. These methods were simulated using the same data, baseline adjustment scenarios, average median relative error methodology, and assumptions. While differing in the triggering mechanics, the BAP and "X of Last 10 Days" methods both include actual metered load data in the baseline calculation from some days when demand reduction offers clear. This is necessary because as previously demonstrated the customer baseline will become biased and inaccurate without the inclusion of new, more recent data to calculate the baseline.

2.2.3.1 Baseline Accuracy Price (BAP)

The concept of the Baseline Accuracy Price is to establish a method for refreshing the baseline with current data to minimize bias in the baseline. When the customer baseline was continuously refreshed, the trend of Median Relative Error did not exceed 2.0% during the time-period of greatest bias, September 1 – December 31, 2010. Using the least biased baseline method (ISO-NE 90/10 with Symmetric Adjustment) as indicated in the analysis, KEMA determined the maximum number of consecutive event days that could occur before the maximum acceptable bias of 2% was exceeded.[13] The maximum number of consecutive event days was established using historic LMP data starting on September 1, 2010 and establishing a trend line of the median relative error observed in the simulated customer baseline data through the end of the year.[14] Using historic data from 2007 the ISO-NE 90/10 with a Symmetric Adjustment did not exceed 2.0% relative error until thirteen (13) consecutive event days had occurred.

As part of an analysis conducted for ISO-NE, CRA calculated ISO-NE system monthly BAPs to meet the 13 day criterion. Table 2 provides the ISO-NE system monthly BAPs, which range from $39.10 to $70.20/MWh. In each month in 2010, the BAP is greater than the DRTP in the same month. The BAP mechanism does not restrict the ability of the DR to offer and clear at the DRTP. However, when the LMP in price responsive intervals is less

[13] This customer baseline variation was selected because it had the least amount of bias of the three that were tested. The other two were the ISO-NE 90/10 with Asymmetric Adjustment and the ISO-NE 90/10 with No Adjustment. Both of these alternative methods had a shorter number of consecutive days before the bias exceeded ±2% relative error.

[14] The trend of the median relative error provides an estimate of the bias observed in the baseline method. This time period was selected because it was the period of highest bias observed in the data.

than or equal to the BAP, event days will be included in the customer baseline calculation in order to ensure that the baseline includes contemporary data.

Table 2: ISO-NE System Baseline Accuracy Prices

Month	Baseline Accuracy Price
January	$ 70.2
February	$ 55.9
March	$ 43.5
April	$ 39.1
May	$ 55.7
June	$ 51.0
July	$ 67.2
August	$ 59.5
September	$ 61.2
October	$ 43.2
November	$ 52.4
December	$ 64.3
Maximum	**$ 70.2**

2.2.3.2 Alternative Baseline Refreshment Mechanism (X of Last 10 Days)

Based on feedback from Market Participants at the NEPOOL Markets Committee meeting on June 2, 2011 an alternative baseline refreshment mechanism using an administrative rule that is independent of the offer price or the LMP was also evaluated. The alternative approach is called “X of Last 10 Days”.

Under the “X of Last 10 Days” method, the decision to include actual metered load data in the baseline calculation on any given day is made by counting the number of days, over the past 10 days of the same day type (i.e., weekdays), on which actual metered load data was included in the baseline calculation. If the number of “included” days over the past 10 days is less than the minimum criteria, then the day’s actual metered load data is included in the baseline calculation – regardless if the offer cleared on that day or not. Ten days was selected as the historic period of interest because the ISO-NE 90/10 baseline is effectively a

10-day rolling average of interval meter data from days on which no events have occurred. The initial baseline is a 5-day average of the actual metered load[15]. The baseline for each day going forward is calculated as .90 times the baseline from the previous day plus .10 of the meter data for the current day. This weights meter data for each new day at 1/10 (0.10), the same weight it would have in a 10-day average. If a longer historic period were used in the calculation it would increase the time-period before refreshment during periods of consecutive event days, which is what the baseline refreshment mechanism is designed to correct.[16]

2.2.4 Simulation Results of Baseline Refreshment Mechanisms

The BAP and "X of Last 10 Days" method were evaluated using the same three baseline variations as the previous simulation (Asymmetric Adjustment, No Adjustment and Symmetric Adjustment) during the September 1 - December 31, 2010 time-period. All assets were assumed to offer at the DRTP and clear in hours where the DRTP was less than or equal to the 2010 LMP. To test the sensitivity of the "X of Last 10 Days" method to the number of included days, KEMA varied the minimum criteria (or "X") from 1 to 5 days.

Table 3: Summary of Relative Error with Baseline Refreshment Mechanisms

Adjustment Type	Without BAP	With BAP	At least x of last 10 days included in				
			1	2	3	4	5
Asymmetric	18.10%	9.60%	13.10%	10.50%	8.30%	7.00%	5.90%
Unadjusted	17.00%	8.40%	11.90%	9.40%	7.00%	5.60%	4.60%
Symmetric	10.40%	**4.70%**	7.00%	5.30%	**4.00%**	3.10%	2.50%

The ISO-NE 90/10 with Symmetric Adjustment methodology was the best performer using both methods. Using the BAP with ISO-NE 90/10 with Symmetric Adjustment resulted in an average relative error of 4.7%, which is a significant improvement over the 10.4% in the

[15] Currently an initial baseline is calculated using the average of 5 days of interval meter data. ISO-NE is proposing to change this to use 10 days of interval meter data.

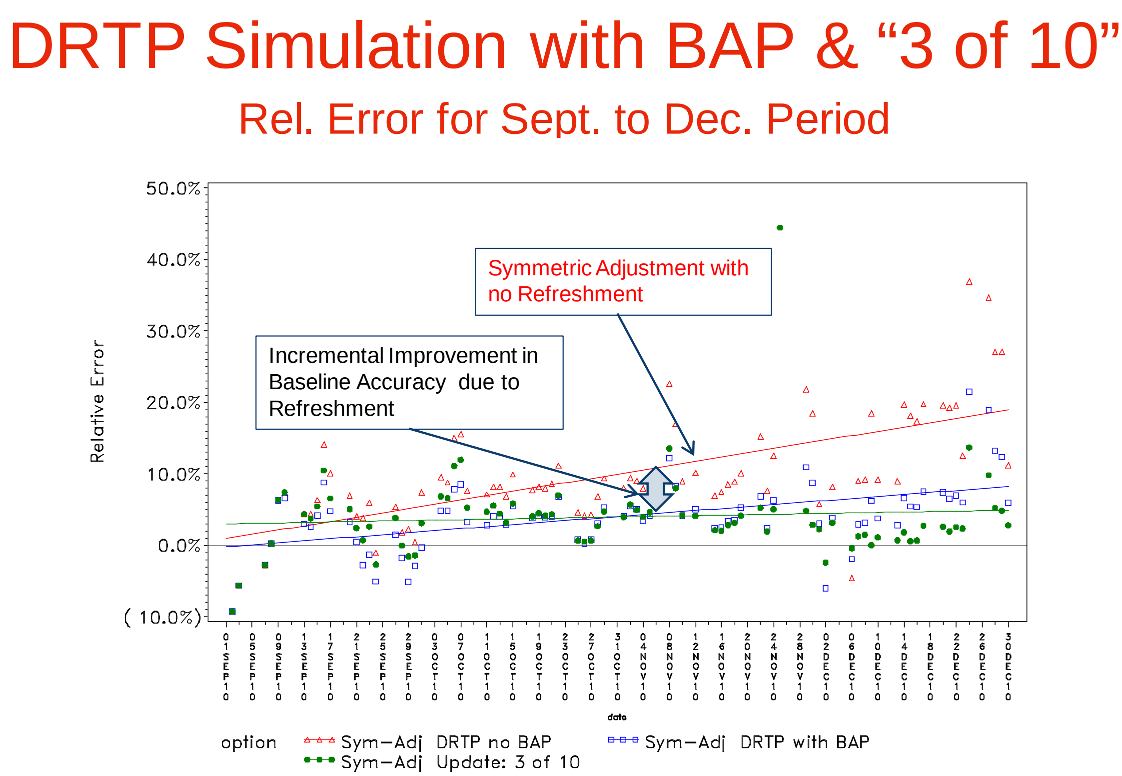
[16] If the ratio were changed from "3 of 10" to "6 of 20" the time-period before refreshment during consecutive event days would double from 7 days (10-3) to 14 days (20-6). Longer historic periods were not tested, because they would result in increased bias by increasing the number of consecutive event days before the baseline is refreshed with current data.

previous simulation. Using the “3 of Last 10 Days” with ISO-NE 90/10 with Symmetric Adjustment resulted in an average relative error of 4.0%, which is the “X of Last 10 Days” result that is closest to the BAP result.

Figure 2 provides a graphical presentation of the simulation results that compares the ISO-NE 90/10 with Symmetric Adjustment under three scenarios as follows:

- With no Baseline Refreshment Mechanism (Red Triangles)
- With Baseline Accuracy Price (Blue Squares)
- Using “3 of Last 10 Days” (Green Squares)

Figure 2: Comparison of Simulation Results BAP and “3 of Last 10 Days”



The simulation results clearly indicate that the relative error is greatly reduced when either of the baseline refreshment mechanisms was used.

2.2.5 Analysis of Baseline Adjustment Calculation

At the same time as the alternative “X of Last 10 Days” method was analyzed, further review of the baseline adjustment was conducted. The current method of determining the time-period used to calculate the baseline adjustment, ISO-NE standard adjustment , uses the two-hour period starting two and one half hours prior to the start of the event. This methodology was developed under the assumption that events would rarely, if ever, start prior to 7 a.m. The KEMA analysis was conducted assuming that events could start in any hour of the day. Based on this assumption a simplified variation of the current ISO-NE standard adjustment calculation was used in all simulations. In this variation, no baseline adjustment was applied on days when an event started during one of the first three hours of the day (“start based adjustment”). This was done to avoid introducing possible bias since the time-period used to calculate the adjustment (the two-hour period starting two and one half hours prior to the start of the event) would use hours from the previous day, which might not provide a good estimate of the baseline and load in the early morning hours. After the initial presentation of results on June 2, 2011, it was determined that a significant number of event days were not being adjusted for any of the baseline methodologies and this was a possible source of bias. As a result, an additional analysis was performed to evaluate baseline performance when the ISO-NE standard adjustment calculation was applied to the baseline regardless of the start time of the event.

Using the ISO-NE standard adjustment, the accuracy of the ISO-NE 90/10 baseline with Symmetric Adjustment improved from an average relative error of 10.4% to 6%. A similar improvement was achieved when using the baseline refreshment mechanisms in conjunction with the ISO-NE standard adjustment. The ISO-NE 90/10 baseline with Symmetric Adjustment and the BAP improved from 4.7% bias to 2.9%. and the ”3 of the Last 10 Days” method improved from 4.0% bias to 2.7% bias. The analysis indicates that the ISO-NE standard adjustment calculation does not introduce additional bias and resulted in improved baseline accuracy over the start based adjustment calculation. Table 4 shows the results of using the ISO-NE standard adjustment in all scenarios. Note that for ISO-NE 90/10 with Asymmetric Adjustment the relative error actually increases when the ISO-NE standard adjustment is used. This is because the Asymmetric Adjustment carries the upward bias. Using the start based adjustment (where a significant number of days had no adjustment applied) this ongoing upward bias was minimized since the Asymmetric Adjustment was not applied on every event day. When the Asymmetric Adjustment is applied on every day, the bias increases. As expected, the unadjusted (No Adjustment) results remain unchanged.

Table 4: Summary of Relative Error with Daily Adjustment Rule

Adjustment Type	Without BAP	With BAP	At least x of last 10 days included in				
			1	2	3	4	5
Asymmetric	19.00%	10.80%	14.20%	11.70%	9.50%	8.10%	7.00%
Unadjusted	17.00%	8.40%	11.90%	9.40%	7.00%	5.60%	4.60%
Symmetric	6.00%	**2.90%**	4.30%	3.50%	**2.70%**	2.30%	1.80%

2.3 Conclusions

The baseline accuracy simulations provided consistent results that indicate baseline error is systematic, not noise. The DRTPs calculated using 2010 historic data are low enough to cause demand response offers at the DRTPs to clear virtually every day of the year. The effect of daily clearing has an adverse impact on the accuracy of all the baseline variants tested, because the baseline can become “stuck” with old data that does not reflect contemporary usage. The start date on which demand reduction offers begin clearing the market impacts the magnitude and direction of the baseline bias. A start date in early September had the highest amount of bias observed in the analysis under the daily clearing scenario. This start date was used to evaluate the performance of the three baseline variations with and without the use of baseline refreshment mechanisms.

In terms of the relative accuracy of the three baseline variations evaluated, the ISO-NE 90/10 with Symmetric Adjustment was clearly the top performer under all scenarios tested. Conversely, the current method the ISO-NE 90/10 with Asymmetric Adjustment was the poorest performer in terms of accuracy and bias. The ISO-NE 90/10 with No Adjustment performed slightly better than the current method. However, none of the baseline variations were able to remain accurate and unbiased when simulated without refreshment when using the DRTPs as the minimum offer price. Both the BAP and the “X of the Last 10 Days” baseline refreshment mechanisms were able to mitigate the bias that occurs during periods of consecutive event days. The performance of the baseline variants were further improved when the ISO-NE standard adjustment calculation was applied on all event days.

The most accurate baseline was achieved when using the ISO-NE 90/10 with Symmetric Adjustment, with the “3 of Last 10 Days” baseline refreshment mechanism and the ISO-NE standard adjustment calculation. Conversely, the least accurate baseline would be the current baseline method (ISO-NE 90/10 with Asymmetric Adjustment) with no refreshment mechanism and the ISO-NE standard adjustment.

The analyses showed that the most important components of baseline accuracy for the ISO-NE 90/10 baseline methodology are a symmetric baseline adjustment that is applied on every event day and the use of a baseline refreshment mechanism.

2.4 Recommendations

The results of the baseline accuracy simulations identify a serious potential problem with the accuracy of the current ISO-NE 90/10 with Asymmetric Adjustment, which is magnified when there is frequent clearing. In order to mitigate bias to an acceptable level the baseline methodology should be changed to:

- ISO-NE 90/10 with Symmetric Adjustment with,
- a “3 of Last 10 Days” baseline refreshment mechanism.

While either baseline refreshment mechanism improves the accuracy of the baseline KEMA recommends the “3 of Last 10 Days” method for the following reasons:

- As tested, the “3 of Last 10 Days” was the more slightly accurate of the two refreshment mechanisms.
- The “3 of Last 10 Days” is more transparent and easier to administer for both Market Participants and the ISO compared to the BAP approach, which requires periodic calculations and updates.
- The “3 of Last 10 Days” does not introduce another price threshold in addition to the DRTP based on the Commission’s net benefits test as required by Order No. 745.
- The “3 of Last 10 Days” does account for past clearing of events when determining whether an event day should be included in the baseline calculation, which the BAP would not. This addresses a concern raised by the stakeholders.

ISO-NE should continue to use the ISO-NE standard adjustment calculation on every day where interruptions occur.

Implementation of ISO-NE 90/10 with Symmetric Adjustment and a “3 of Last 10 Days” baseline refreshment mechanism in conjunction with continued use of the ISO-NE standard adjustment calculation is recommended to decrease baseline bias, improve baseline accuracy and achieve more accurate demand reduction performance calculations.

Attachment 6

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER11-___-000**
New England Power Pool	**)**	

TESTIMONY OF DAVID LAPLANTE

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

A: My name is David LaPlante. I am the Vice President of Market Monitoring for ISO New England Inc. (the "ISO"), One Sullivan Road, Holyoke, Massachusetts 01040-2841. As Vice President of Market Monitoring, I serve as the head of the ISO's Independent Market Monitor ("IMM").

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A: I have a Bachelor's degree in statistics from Princeton University and a Master's Degree in City and Regional Planning from Harvard University. I have over 22 years of experience in the energy and utility industry. Between 1989 and 1994, I spent five years supervising and conducting power system reliability studies at the New England Power Pool. I have been working on the deregulation of the wholesale electric industry in New England since 1994. When serious discussions about deregulation of the wholesale electricity market in New England began, I was part of the team that negotiated the contract between the ISO and the New England Power Pool that led to the creation of the ISO in 1997.

I then led the ISO team that worked with NEPOOL to develop and implement the region's first set of wholesale markets in 1999. Following that, I was responsible for the market design portion of the Standard Market Design implemented by the ISO in March 2003. I was integrally involved in the Forward Capacity Market settlement agreement and in the development of the capacity market rules that implement the settlement agreement. In July 2008, I took the position of Vice President of the Internal Market Monitoring Unit at the ISO.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of this testimony is to explain revisions to Appendix A of Market Rule 1 (Market Monitoring, Reporting and Market Mitigation) included in the ISO's Order No. 745 compliance package on price responsive demand. My testimony also explains the related changes to the ISO New England Information Policy.

Q: EXPLAIN THE PURPOSE OF THE CHANGES TO APPENDIX A.

A: The Appendix A changes are designed to help satisfy the requirements of Order No. 745 related to measuring and verifying the performance of demand response resources and the establishment of accurate baselines to assure that demand reduction are genuine. In Paragraphs 94 and 95 of Order No. 745, the Commission directed

> ISOs and RTOs to review their current requirements in light of changes in this Final Rule and develop appropriate revisions and modifications, if necessary, to ensure that their baselines remain accurate and that they can verify that demand response resources

> have performed. Specifically, we direct each RTO and ISO to include as part of the compliance filing required herein, an explanation of how its measurement and verification protocols will continue to ensure that appropriate baselines are set, and that demand response will continue to be adequately measured and verified as necessary to ensure the performance of each demand response resource. If necessary, each RTO and ISO should propose any changes needed to ensure that measurement and verification of demand response will adequately capture the performance (or non-performance) of each participating demand response market participant to be consistent with the requirements of this Final Rule.
>
> Finally, we agree with ISO-NE IMM that demand reductions that are not genuine may be violations of the Commission's anti-manipulation rules. Allegations of such behavior will continue to be investigated, and when appropriate, sanctions will be brought to bear.

Q: HOW WERE THE APPENDIX A CHANGES DEVELOPED?

A: The IMM reviewed the Order No. 745 compliance package the ISO developed, then developed changes to Appendix A to provide for effective monitoring of demand response resources.

Q: WHAT APPROACH WILL THE IMM TAKE FOR MONITORING DEMAND RESPONSE RESOURCES?

A: The approach the IMM follows for monitoring demand response resources differs from the monitoring and mitigation approach taken for supply resources. The conduct/impact approach the IMM uses for supply resources is based upon calculating a reference level for each resource which is intended to represent a competitive offer for that resource. If the resource's actual offer exceeds that level by more than a given threshold, it is said to have violated the offer conduct threshold. If a resource that violates the offer conduct threshold also has an impact on the market price, it is subject to mitigation.

The approach the IMM will take for monitoring demand response resources is different. The IMM does not calculate a reference level for each demand response resource, and Appendix A does not provide any specific mitigation measures for demand response resources. Instead, the IMM will monitor the performance of demand response resources to identify behavior that needs further investigation to ensure accurate baselines and genuine demand reductions. Additionally, demand response providers may attempt to exercise market power by offering to reduce demand at a price that is consistently below their demand response resource's opportunity costs in an attempt to lower the market clearing price, or by offering to reduce demand consistently above their demand response resource's opportunity costs in an attempt to raise the market clearing price. If the IMM finds such behavior is suspect, after a thorough review, it will refer the participant to the Commission's Office of Enforcement.

Q: DESCRIBE THE REVISIONS TO APPENDIX A INCLUDED IN THE ISO'S ORDER NO. 745 COMPLIANCE PACKAGE.

A: To support the IMM's ability to monitor and review demand response resources, the ISO's Order No. 745 compliance package adds a new subsection to Appendix A to clarify that the IMM has the authority to obtain information from demand response providers necessary for it to determine:

i. the opportunity costs associated with Demand Reduction Offers;
ii. the accuracy of Demand Response Baselines;
iii. the method used to achieve a demand reduction; and
iv. the accuracy of reported demand levels.

Q: WHY HAS THE IMM DECIDED NOT TO INCLUDE PROVISIONS IN THE ORDER NO. 745 COMPLIANCE PACKAGE THAT WOULD ALLOW IT TO MITIGATE DEMAND RESPONSE RESOURCES?

A: The main reason for not mitigating demand resources is a practical one; it would be very difficult to develop a competitive offer or reference price to which to mitigate each demand resource. The competitive offer for a demand response resource should be based on its opportunity cost of not consuming the electricity. The opportunity cost of not consuming electricity is the value of the service or product that is not produced, or the cost of deferring its production. Since each customer has a different, time-varying opportunity cost based on its business, it is impractical to establish, in advance, reference levels for each resource that reflect their unique, time-varying opportunity costs. In contrast, for supply resources, it is reasonably straightforward to calculate the cost of producing a megawatt hour of energy from a generating unit given its technology and fuel type.

Additionally, demand response providers face different incentives than generators. For example, if demand responses providers are net buyers in the market, their incentives are to lower the price – not raise it, like suppliers –

leading to the consideration that the IMM should monitor demand bids to determine if they are seeking to lower the price in a non-competitive manner. In contrast, demand response providers that aggregate demand response resources are usually not buyers in the energy market, and would not benefit from lower energy prices. Instead, they earn revenues based on the energy price when demand is reduced, and therefore, their incentive would be to raise the price at which demand is reduced, just like some generators. While the mitigation approach for generators is relatively straightforward since generators always have the incentive to raise prices, the more complicated incentive structure of demand response resources makes it difficult to determine the appropriate mitigation approach for such resources.

Q: GIVEN THAT THE IMM BELIEVES IT MAY BE TOO DIFFICULT TO ESTABLISH REFERENCE LEVELS TO MITIGATE DEMAND REDUCTION OFFERS, DOES THE IMM BELIEVE THAT MONITORING ALONE WILL ASSURE COMPETITIVE BEHAVIOR BY DEMAND RESOURCES?

A: Yes, the IMM believes that, while the behavior for demand response providers is complicated by the reality that demand response resources are more asset specific than supply resources, the market forces encouraging competitive behavior by demand response providers are sufficiently strong so that competitive behavior of demand response resources can be assured in a cost effective manner using a monitoring approach based on review and referral rather than reference levels and mitigation. Specifically, demand response providers that offer at low prices every day will likely be dispatched frequently causing frequent disruptions of the customers they serve. Because it is unlikely that customers prefer to have their service disrupted frequently, offers at low prices every day may indicate strategic bidding behavior to manipulate the baseline or otherwise receive payments for demand reductions that are not genuine. With access to the appropriate information, such behavior should be detectable by the IMM and then referred to the Commission's Office of Enforcement, if necessary.

If a demand response provider attempts to raise prices, it faces competition in the energy market. If the demand response provider raises the price above the level at which its assets wish to interrupt, it will lose revenue through competition. Given these incentives, the IMM is comfortable that the monitoring approach outlined here is sufficient. Of course, if the IMM finds after implementing these changes that additional revisions and modifications are appropriate, the IMM will propose them, as the Commission has so directed under Order No. 745.

Q: DESCRIBE THE CHANGES TO THE ISO NEW ENGLAND INFORMATION POLICY.

A: The Order No. 745 compliance package amends the ISO New England Information Policy to clarify that demand response information provided at the request of the Internal Market Monitor pursuant to Section III.A.12 is confidential information and subject to the protections afforded to confidential information.

Q: WHEN WILL THE APPENDIX A AND INFORMATION POLICY CHANGES BECOME EFFECTIVE?

A: All of the changes will become effective on June 1, 2012 when the transition period rules become effective and will remain in effect thereafter.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on ______________

____

David LaPlante

Vice President-Market Monitoring

ISO New England Inc.

Attachment 7

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