



July 1, 2013

BY ELECTRONIC FILING

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

RE: **ISO New England Inc. and New England Power Pool, Docket No. ER13-000, Energy Market Offer Flexibility Changes** -

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act (“Section 205”),¹ ISO New England Inc. (the “ISO”), joined by the New England Power Pool (“NEPOOL”) Participants Committee² (together, the “Filing Parties”),³ hereby electronically submits this transmittal letter and revised Tariff sections involving energy market enhancements that will provide greater flexibility for Market Participants to structure and modify their Supply Offers in the day-ahead and real-time markets (the “Offer Flexibility Changes”).

In support of the Offer Flexibility Changes, the ISO is submitting the supporting joint testimony of Dr. Robert G. Ethier, Vice President, Market Development for the ISO and Mr. Christopher A. Parent, Manager of the Market Development Department (the “Ethier/Parent Testimony”), which is sponsored solely by the ISO. The Ethier/Parent Testimony describes and explains the benefits associated with the changes. The ISO also is submitting the supporting testimony of Dr. Mario S. DePillis, Jr., an Economist with the ISO’s Internal Market Monitor (the “DePillis Testimony”), which is sponsored solely

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

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

³ Under New England's Regional Transmission Organization (“RTO”) arrangements, the rights to make this filing of changes to the Market Rule under Section 205 of the Federal Power Act are the ISO's. NEPOOL, which pursuant to the Participants Agreement provides the sole Participant Processes for advisory voting on ISO matters, supported the changes reflected in this filing and, accordingly, joins in this Section 205 filing.

by the ISO. The DePillis Testimony explains the changes that are being made to Appendix A (Market Monitoring, Reporting and Market Power Mitigation) of Market Rule 1 to conform the existing mitigation rules to the new, more flexible Supply Offer structure.

As addressed in Section II of this transmittal letter, the Filing Parties request an effective date of December 3, 2014 for the Offer Flexibility Changes. ***For the reasons discussed in Section II, the Filing Parties also request that the Commission issue an order accepting the Offer Flexibility Changes by October 1, 2013.***

I. THE OFFER FLEXIBILITY CHANGES IN CONTEXT

Section I of this transmittal letter reflects the plans of the ISO for proposing a series of ISO Tariff changes, some of which already have been filed and some of which have yet to be presented to stakeholders or taken through the complete stakeholder process.⁴ The ISO's proposals that have not been filed yet very well may change during the stakeholder review process. Further, NEPOOL does not have direct knowledge of the information about generator performance that is provided by the ISO in this section. Therefore, NEPOOL is not in a position to join in providing the contextual information included in this Section I. Both the ISO and NEPOOL intend to continue to work together to review the proposals that have not yet been filed and hope that the ultimate proposals will be broadly supported.

The Offer Flexibility Changes are another step in a series of operational and market improvements that the ISO is working on with stakeholders to address emerging concerns over New England's increased reliance on natural gas to generate electricity and over resource performance issues. During late 2012 and the first part of this year the ISO has filed with the Commission a number of market rule changes to address these emerging concerns, and is in the process of preparing a number of additional enhancements for filing in June and later this year. One of these sets of tariff revisions provides a solution to address fairly significant reliability concerns for the 2013-2014 winter season. Each set of proposed changes is being taken through the full stakeholder process as it is developed.

In this proceeding, the Commission is requested to rule on the Offer Flexibility Changes. To provide context, this section of the transmittal letter identifies the ISO's additional proposals for addressing its concerns with resource performance and gas-electric coordination, and the role of the Offer Flexibility Changes relative to those proposals.

The ISO's concerns are prompted by two sets of related issues in New England. First, New England's increased reliance on natural gas-fueled generation raises questions

⁴ NEPOOL has not voted on the ISO's plans for changes to the markets except as indicated with respect to particular proposals.

for the ISO about whether the wholesale electricity markets require enhancements to ensure both reliability and market efficiency given the structure of the gas markets and the risks of increasing reliance on the supply of natural gas. Second, generating resource operations during periods of stressed system conditions revealed that many resources did not perform at the levels of their offered parameters.

The ISO's analysis of operational performance of existing resources during stressed system conditions - times when resources' performance is essential to reliability - indicates that older units that are relied upon for peaking service, ramping or reserves are sometimes not performing to the full extent of their offered parameters.⁵ These shortcomings became manifest in operational events on June 24, 2010, September 2, 2010, and January 24, 2011 (including a NERC violation related to inadequate generation contingency response on September 2, 2010).⁶ More generally, an examination, conducted in early 2012, of dispatch response performance following the 36 largest system contingency events over the last three years indicates that, on average, the response rate for New England's non-hydro generating resources was less than 60% of the amount requested during the events. The non-hydro generators that were dispatched to address these contingencies were largely fast-start resources and spinning reserve resources, and the dispatch performance during these events is a low response rate for resources that are tasked with providing reserves in New England. In sum, at times of greatest need, many resources did not deliver based on their offered parameters.

Increased demand for natural gas in New England has increased competition for the use of the region's natural gas pipeline capacity. Since the opening of wholesale markets in the late 1990s there have been approximately 12,000 MW of combined cycle units built in New England, all fueled by natural gas. It appears that the majority of this capacity does not have long-term firm transportation rights to deliver natural gas. In 2000, natural gas supplied 15% of New England's electricity. That increased to 52% in 2011.⁷ During this period the demand for natural gas for space heating also grew.

The increased reliance on natural gas-fueled generation has heightened ISO concerns regarding risks to reliability.⁸ In various instances natural-gas fueled generators

⁵ *Strategic Planning Risk Summary* (21 April 2011), p. 4, available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/spd_risk_summary_apr_2011.pdf.

⁶ *Id.* at p. 4.

⁷ The increase in demand for natural gas was helped by a decrease in the price of shale gas delivered from west of New England, an increase in the price of coal and continued high prices for oil.

⁸ In the summer of 2012, the ISO released a white paper that reviews the reliability issues posed by New England's increasing dependence on gas-fired generators. The white paper discussed the issues and presented a number of possible solutions to mitigate the risks. See ISO New England Inc., *Addressing Gas Dependence*, July 2012, available at <http://www.iso->

have not provided energy when dispatched, claiming that they were unable to procure natural gas or transportation services or that the gas was too expensive in real time.⁹ As a result, the ISO has concerns that generators which are being counted on for reserves may not be able to provide energy if needed. As the region continues to rely more heavily on gas, and with the potential for unit retirements that could remove the capacity surplus that has existed in New England in recent years, the risks from these circumstances will increase, in particular when coupled with more conventional contingencies that New England has traditionally experienced. The ISO and NEPOOL have already identified and filed a number of changes and the ISO is exploring with its stakeholders a number of additional changes to the New England markets designed to address these reliability concerns.

The 2012-2013 winter presented additional challenges and risks to the reliable operation of the electrical system, which, in addition to the proposed market rule changes, are prompting more immediate actions for the 2013-2014 winter season. During the 2012-2013 winter the ISO saw a number of instances in which natural gas-fueled generation did not have sufficient fuel to provide energy at or even near the generator's stated capacity as reflected in their daily offers. Increased and relatively extreme volatility in natural gas prices during the 2012-2013 winter exacerbated fuel procurement issues, and also showed that many dual-fuel and oil-only resources did not have sufficient fuel to allow for reliable operation during extended and repeated periods of cold weather.

To address the circumstances described above, the ISO is in the process of making a series of market rule changes to address resource performance and market efficiency issues. Several Section 205 filings have been made by the ISO and, in most cases, joined by NEPOOL, since late 2012 for market rule changes that either have been implemented or will be implemented in the near-term. Several additional changes are being prepared for filing during June. In addition to the Offer Flexibility Changes being filed herewith, these changes will put in place a largely out-of-market stop-gap program to address reliability concerns for next winter and two reserve market revisions that will also support reliability and greater market efficiency for the next winter. Two additional sets of proposed revisions to the Forward Capacity Market rules to tighten the shortage event trigger and redesign capacity market incentives are currently being discussed with stakeholders and will likely be filed with the Commission later this year. Each set of proposed changes is being taken through the full stakeholder process as it is developed.

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ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/natural-gas-white-paper-draft-july-2012.pdf.

⁹ In fact, the New England Power Generators Association has filed a complaint, which the ISO has answered, that squarely addresses generator obligations in the markets. *New England Power Generators Association v. ISO New England Inc.*, Complaint and Request for Expedited Consideration, Docket No. EL13-66-000 (filed May 17, 2013); *New England Power Generators Association*, Answer of ISO New England Inc., Docket No. EL13-66-000 (filed June 6, 2013).

Market enhancements and revisions filed to date. The following summarizes the market rule enhancements and revisions that have been filed with the Commission during late 2012 and the first part of 2013 to address resource performance and market efficiency issues. The majority of these have been implemented, and the remaining changes will be implemented in the near term.

- Increasing Ten-Minute Non-Spinning Reserve to be procured in the Forward Reserve Market. In July 2012, the ISO increased the amount of Ten-Minute Non-Spinning Reserve it requires in real-time operation of the system in response to the historical performance of reserve resources. In January 2013, in Docket No. ER13-465-000 the Commission accepted a market rule change to increase the amount of Ten-Minute Non-Spinning Reserve that is procured in advance through the Forward Reserve Market. Permitting an additional amount of reserve to be procured in the Forward Reserve Market helps support the availability of reserves to meet the increased real-time reserve requirements. This change became effective on March 1, 2013 following the Commission's issuance of a letter order on January 17, 2013.
- Modifying generating resource auditing requirements and procedures. In January 2013, the Commission accepted in Docket No. ER13-323-000 modifications intended to provide the ISO with a more accurate assessment of the 10 and 30 minute reserve capability of reserve resources, which should work in conjunction with the modifications to the real-time reserve requirements and the proposal to modify the forward reserve requirements to ensure sufficient reserve resources. These changes became effective on June 1, 2013. An additional series of changes filed in this same docket to address the auditing of the claimed capability of generator assets will go into effect later this year.
- Allowing the ISO to share information concerning the scheduled output of natural gas-fired generating resources with the operating personnel of the interstate natural gas pipeline companies serving New England. The ISO has concluded that, by sharing expected generation output schedules confidentially with the pipeline operators, the pipeline operators may be able to provide confidential information to the ISO operators on gas availability that will allow the ISO to better anticipate and address potential reliability problems in the event that there is insufficient fuel for all gas-fired generators to meet their schedules. In an order on rehearing issued in January 2013 in Docket No. ER13-356-000, the Commission allowed proposed revisions to the ISO New England Information Policy to go into effect on an interim basis and subject to certain modifications.
- Accelerating the closing time of the Day-Ahead Energy Market. In order to provide the ISO and Market Participants with additional time to prepare for the Operating Day, the ISO and NEPOOL both had alternative proposals to close the Day-Ahead Energy Market earlier in the day and to provide for earlier clearing of the market and earlier completion of the Reserve Adequacy Analysis process.

The earlier completion of the day-ahead market processes allow the ISO to commit long lead-time resources earlier and allow participants with gas-fired resources to learn their next-day commitments earlier so that they have more time to make fuel arrangements reflecting those commitments. In April 2013 the Commission accepted NEPOOL's proposal to move the closing of the day-ahead market to 10:00 a.m., and this change became effective on May 23, 2013.

Additional solutions filed during June/July 2013. Including the Offer Flexibility Changes, the ISO and NEPOOL have filed four tariff changes in the past month. These filings involve changes to the energy and reserve markets, as well as a special program to address near term reliability concerns during the 2013-14 winter season. All of these changes, except the Offer Flexibility Changes, are expected to be implemented in time to help address reliability concerns for the 2013-2014 winter season:

- Reliability Project for Winter 2013-2014. In response to operational issues during the 2012-2013 winter, the ISO has been working with stakeholders to develop a program for the 2013-2014 winter season that will help address near term reliability concerns. To address an estimated reliability gap of approximately 1.1 – 1.5 million MWh, or, in fuel terms, about 1.9 – 2.6 million barrels of oil, the ISO's proposal incorporates components for dual fuel generators, demand response and oil-fired generators. The proposal asks generators with oil-fired resources and certain dual fuel resources to establish a specified amount of oil inventory for the winter in exchange for an "as bid" monthly payment, provides payments for dual fuel units to ensure their switching capability through a test, and procures new demand response assets (and additional capacity from existing assets) to provide energy in case of a reliability event. These changes were filed with the Commission on June 28, 2013 in Docket No. ER13-1851 and are subject to an aggressive implementation timetable if they are accepted.
- Offer Flexibility Enhancements. As discussed elsewhere in this filing, currently participants are permitted to change Supply Offers (*i.e.*, to modify offers used in the Day-Ahead Energy Market) only during a two-hour period starting at 1:30 p.m. on the day before the Operating Day. No offer changes are permitted during the Operating Day. The Offer Flexibility Changes will allow offer changes to be made in real time during the Operating Day, which will improve a market participant's ability to reflect in its energy market offer the cost of obtaining fuel in real time. Offers which are more reflective of actual fuel prices will improve energy market price signals and will permit a better match between those prices and the cost of procuring fuel in real time. The ISO intends to implement the Offer Flexibility Changes on December 3, 2014.¹⁰

¹⁰ This implementation timetable is aggressive and reflects the high priority that the ISO and New England stakeholders have placed on the implementation of the Offer Flexibility Changes. The ISO will have a significant amount of work to do to create and then integrate the hourly offer requirements into the existing offer and clearing mechanisms; this implementation process is a

- Forward Reserve Market incentives changes. To improve the performance incentives associated with the Forward Reserve Market, the ISO is proposing market rule changes so that the Forward Reserve Failure-to-Reserve Penalty will better incent appropriate performance by reserve resources and changes to the “trigger” that is used to determine whether a resource should be assessed a Forward Reserve Failure-to-Activate Penalty. These changes were filed on June 20, 2013 in Docket No. ER13-1733 and are proposed to become effective on October 1, 2013.

- Procurement of additional reserves and establishment of a Reserve Constraint Penalty Factor (“RCPF”) for the replacement reserve requirement. To better reflect the cost of actions that the ISO takes to maintain system reliability in market prices, the ISO will be: (1) using a replacement reserve requirement as allowed under Operating Procedure No. 8 to procure additional reserves, and; (2) proposing market rule changes to set an RCPF (*i.e.* a price cap) of \$250/MWh for the replacement reserve requirement. The proposed market rule changes were filed on June 20, 2013 in Docket No. ER13-1736 and are proposed to become effective on October 1, 2013. Earlier, on March 22, 2012, the ISO also filed a tariff change to increase the RCPF system-wide value for Thirty-Minute Operating Reserves (“TMOR”) from \$100/MWh to \$500/MWh. The expected benefits of the increase in the RCPF system-wide value for TMOR included the ability to rely more frequently on the unit dispatch system to automatically re-dispatch resources and avoid reserve deficiencies and better alignment of reserve market price signals and the financial incentives of reserve suppliers. The Commission accepted the TMOR RCPF change in Docket No. ER12-1314-000 on May 21, 2012.

Additional Forward Capacity Market Solutions. The ISO is working with stakeholders to review two proposed modifications to the Forward Capacity Market. It is possible that further consideration with stakeholders will indicate that modifications,

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major project that will require modifications to numerous database functions and information technology infrastructures. In addition, because of the nature of enhancements, a number of revisions will need to be made to other parts of the ISO Tariff, including Net Commitment Period Compensation and capacity market revisions. The ISO has begun presenting some of these additional changes to stakeholders and anticipates filing some of the proposed changes later in the summer. However, it is anticipated that all changes will not be filed with the Commission until later in 2013 or early 2014. Given both the scope and depth of the implementation process, as well as the need for additional conformation tariff changes, the ISO currently plans to complete the implementation on December 3, 2014, in time for the 2014-15 winter season.

alternatives or additional courses of action to those described below, are more appropriate. The following summarizes the ISO's currently planned proposals:¹¹

- Tightening the FCM Shortage Event Trigger. The ISO is discussing with stakeholders tightening the Shortage Event trigger in the Forward Capacity Market to ensure that a Shortage Event is triggered earlier in a period of reserve deficiency. Currently, the Shortage Event is triggered when there has been a deficiency in ten-minute operating reserve for 30 or more minutes. The ISO is in the process of reviewing proposed market rule changes to address these modifications with stakeholders and intends to file these changes with the Commission in August of 2013.
- Redesigning the Forward Capacity Market to provide appropriate incentives for performance and commensurate consequences for failures to perform. The ISO issued a white paper reflecting its planned proposal to change the structure of the incentives and consequences that would apply when the system is short of reserves, and for the incentives to be large enough to justify investment to improve the reliability and performance of resources. Under the proposal, all resources would be subject to the performance standard, eliminating all exceptions from performance now contained in the FCM rules.¹² The ISO has received significant stakeholder feedback on this project, including discussion on alternative proposals, and currently intends to propose market rule changes for stakeholder consideration in 2013.

As a transition mechanism from the 2013-2014 winter reliability project discussed above and the immediately preceding project on FCM performance incentives, the ISO intends to propose a scaled down version of the performance incentives project to purchase a winter-based reliability product for the period between the upcoming winter and the winter of 2018-2019 when the full performance incentive proposal is planned for implementation.

II. REQUESTED EFFECTIVE DATE, WAIVER OF 120-DAY PRIOR NOTICE REQUIREMENT AND REQUEST FOR COMMISSION ACTION BY OCTOBER 1, 2013

The Filing Parties request an effective date for the Offer Flexibility Changes of December 3, 2014 and waiver of the 120-day notice requirements of 18 C.F.R 35.3 (2012). The filing of the Offer Flexibility Changes well in advance of the expected

¹¹ The ISO also is evaluating whether to propose additional changes to address the concerns discussed above.

¹² Available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf.

effective date provides additional notice to stakeholders prior to the implementation of these important changes to the way that Market Participants submit their offers for the wholesale electricity markets.

The Filing Parties also request that the Commission issue an order in this proceeding by October 1, 2013. As discussed above in Section I, the ISO and stakeholders are working on additional changes related to the Offer Flexibility Changes. These additional changes will include changes to the Net Commitment Period Compensation (“NCPC”) mechanism to: (1) ensure that the NCPC calculations are aligned with the ability of Market Participants to submit offers that vary by hour and change offers in real time, and, potentially; (2) to modify the existing NCPC rules in some cases so that NCPC payments provide better incentives for resource performance. By acting on the Offer Flexibility Changes by October 1, 2013, the Commission will provide information that may be helpful to the ISO and stakeholders before the NEPOOL Participants Committee is expected to consider the proposed NCPC changes at its October 8, 2013 meeting.

III. DESCRIPTION OF THE FILING PARTIES; COMMUNICATIONS

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

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 430 members. The Participants include all of the electric utilities rendering or receiving service under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, demand resource providers, developers and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission,¹³ the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, “NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from

¹³ *ISO New England Inc., et al.*, 109 FERC ¶ 61,147 (2004).

state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff.”

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IV. STANDARD OF REVIEW

These changes are being submitted pursuant to Section 205, which “gives a utility the right to file rates and terms for services rendered with its assets.”¹⁵ Under Section 205, the Commission “plays ‘an essentially passive and reactive role’”¹⁶ whereby it “can reject [a filing] only if it finds that the changes proposed by the public utility are not ‘just and reasonable.’”¹⁷ The Commission limits this inquiry “into whether the rates proposed

¹⁴ Due to the joint nature of this filing, the Filing Parties respectfully request a waiver of Section 385.203(b)(3) of the Commission’s regulations to allow the inclusion of more than two persons on the service list in this proceeding.

¹⁵ *Atlantic City Elec. Co. v. FERC*, 295 F. 3d 1, 9 (D.C. Cir. 2002).

¹⁶ *Id.* at 10 (quoting *City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

¹⁷ *Id.* at 9.

by a utility are reasonable - and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs.”¹⁸ The changes proposed herein “need not be the only reasonable methodology, or even the most accurate.”¹⁹ As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.²⁰

V. THE OFFER FLEXIBILITY CHANGES

The Offer Flexibility Changes can be divided into six overall categories:

1. The ability to modify the cost-related parameters of a Supply Offer or a Demand Bid for a Dispatchable Asset Related Demand after the initial Reserve Adequacy Analysis (“RAA”) process is completed;
2. The ability to submit cost-related parameters of a Supply Offer or a Demand Bid for a Dispatchable Asset Related Demand that may vary by hour, rather than requiring these parameters to be the same for all hours of an Operating Day;
3. Modification of the existing method of implementing self-scheduling that is based on modifying a generating resource’s Economic Minimum Limit to indicate a self-schedule level, to a method that relies on the Market Participant’s ability to submit hourly Supply Offers and change their Supply Offers in real time;
4. The ability to submit a negative offer as low as negative \$150/MWh for External Transactions and the energy Blocks for a Supply Offer, Demand Bid, Increment Offer and Decrement Bid, and;
5. Conforming changes to Appendix A mitigation rules that are required to maintain consistency with the changes that allow Market Participants to submit offers that vary by hour, change offers in real time and submit offers as low as negative \$150/MWh.
6. Clarification and clean-up changes, including: removing defined terms that are no longer applicable; adding defined terms for Supply Offer parameters, and; clarifications to language related to Supply Offers, Demand Bids and External Transactions.

Each category of change is discussed briefly below.

¹⁸ *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

¹⁹ *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

²⁰ *Cf. Southern California Edison Co., et al*, 73 FERC ¶ 61,219 at 61,608 n.73 (1995) (“Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters.” (*citing Bethany*)).

Real-Time Offer Changes

Under the current market structure, Market Participants finalize and submit offers for the Day-Ahead Energy Market by no later than 10:00 a.m. on the day before a particular Operating Day.²¹ After the day-ahead market is cleared and the results posted, Market Participants have the opportunity to modify their offers during a half hour period between 1:30 and 2:00 p.m. (known as the Re-Offer Period) on the day before the Operating Day.²² There is no opportunity to change the cost-related parameters of an offer after the Re-Offer Period.²³ Some offer parameters can be re-declared by a Market Participant in real time to accurately reflect the physical characteristics of a resource.²⁴

Under the Offer Flexibility Changes, Market Participants will be able to change the cost-related parameters of their offers up until 30 minutes prior to the hour in which the offer would apply.²⁵ Specifically, for generating resources, Market Participants will be able to modify the energy Blocks, Start-Up Fee, No-Load Fee, fuel type, and the Regulation Supply Offer price and quantity.²⁶ For Dispatchable Asset Related Demand, Market Participants will be able to modify the energy Blocks of the Demand Bid.²⁷

As described in the Ethier/Parent Testimony, providing Market Participants an opportunity to change offers in real time has several benefits. At the individual Market Participant level, being able to update an offer in real time means that any of a resource's operating costs that have changed to reflect real-time fuel or other costs can be included in the new offer and makes it is more likely that Market Participant's financial incentives and the requirement for resources to follow dispatch instructions are aligned.²⁸ From a broader market perspective, the ability of Market Participants to change offers in real time to reflect the real-time price of fuel or other operating costs means that the energy market dispatch will be more efficient (*i.e.*, that the marginal cost of electricity will be more closely aligned with the marginal costs of fuel).²⁹

²¹ Ethier/Parent Testimony at p. 4.

²² *Id.*

²³ *Id.* at p. 5.

²⁴ *Id.*

²⁵ *Id.* at p. 7.

²⁶ *Id.*

²⁷ *Id.*

²⁸ *Id.* at p. 10.

²⁹ *Id.* at pp. 8, 10.

Offers That Vary By Hour

Under the current market rules, the cost-based parameters of offers generally are the same for every hour of a particular Operating Day (*i.e.*, they have a daily granularity).³⁰ Under the Offer Flexibility Changes, Market Participants will be able to submit cost-related offer parameters that vary by hour.³¹ Specifically, for generating resources, Market Participants will be able to submit hourly values for Start-Up Fees, No-Load Fees, fuel type, energy Blocks and the Regulation Supply Offer price and quantity.³² For Dispatchable Asset Related Demand, Market Participants will be able to submit hourly values for the energy Blocks.³³

Providing Market Participants the ability to submit offers that vary by hour will have the same general benefits as being able to change offers in real time. A Market Participant may have a resource with costs that vary over the course of a day, but the Market Participant is not able to reflect this cost variation in its offers under the existing structure.³⁴ For example, due to the timing of the gas market operating day, a Market Participant may purchase gas at one price for part of a day and at another price for the remainder of the day.³⁵ Being unable to reflect these different fuel costs in a single offer, the Market Participant may adopt a sub-optimal approach, such as averaging the fuel costs.³⁶ For the same reasons discussed above with respect to the ability to change offers in real time, providing Market Participants with the ability to submit offers that vary by hour will avoid instances in which the day-ahead and real-time energy and reserve prices may not properly reflect the actual costs of the marginal resource for a particular hour.³⁷ Providing Market Participants the ability to submit offers that vary by hour will better ensure that market results, Market Participants' financial incentives and the requirement for resources to follow dispatch instructions are aligned.³⁸

Negative Offers

Under the current rules, an offer in the energy market may not be less than \$0/MWh.³⁹ The Offer Flexibility Changes will allow Market Participants to submit

³⁰ *Id.* at pp. 5-6.

³¹ *Id.* at p. 11.

³² *Id.*

³³ *Id.*

³⁴ *Id.*

³⁵ *Id.* at p. 12.

³⁶ *Id.*

³⁷ *Id.* at pp. 12-13.

³⁸ *Id.*

³⁹ *Id.* at p. 17.

offers as low as negative \$150/MWh (referred to as the Energy Offer Floor).⁴⁰ The lower offer floor accommodates the needs of Market Participants with resources that can operate economically (or can increase consumption) at very low energy prices and is more consistent with offer floors used in other regions.⁴¹ The new offer floor will allow Market Participants to submit offers that better reflect the full range of prices at which different types of resources become uneconomic.⁴² From a market efficiency perspective, the lowering of the Energy Offer Floor will allow resource output to be set through an economic dispatch process.⁴³ Under the current rules, the output of all resources with a \$0/MWh offer is modified on a *pro rata* basis when necessary, rather than through an economic dispatch process.⁴⁴

Appendix A Changes

As explained in the DePillis Testimony, the current mitigation rules in Appendix A of Market Rule 1 assume that Market Participants submit a single offer in the day-ahead market that is the same for every hour and that may only be modified once during the Re-Offer Period.⁴⁵ The Offer Flexibility Changes will provide Market Participants the opportunity to submit differing offers for each hour of a day and to change offers very near real time. These changes require substantial modification of the mitigation rules. Briefly, these changes involve:

- The Internal Market Monitor must develop hourly Reference Levels rather than Reference Levels that are fixed for an Operating Day.⁴⁶ Market Participants may change offers in real time based on updated fuel price information, provided that the information is accurate and verifiable, and the hourly Reference Levels also will be updated in real time to reflect this updated fuel price information.⁴⁷
- The Offer Flexibility Changes will significantly increase the number of opportunities Market Participants have to make fuel price adjustments.⁴⁸ This creates the opportunity for Market Participants to use fuel price adjustments as a means to avoid mitigation.⁴⁹ The IMM will use three mechanisms to prevent

⁴⁰ *Id.*

⁴¹ *Id.*

⁴² *Id.*

⁴³ *Id.* at p. 18.

⁴⁴ *Id.*

⁴⁵ DePillis Testimony at p. 2.

⁴⁶ *Id.* at p. 4.

⁴⁷ *Id.* at p. 8.

⁴⁸ *Id.*

⁴⁹ *Id.* at p. 9.

Market Participants from entering fuel price adjustments in order to avoid mitigation.⁵⁰ First, the IMM will set a limit on the fuel price it will use in calculating a resource's Reference Level based on available fuel price indices and market conditions and that is independent of any fuel price adjustment submitted by a Market Participant. Second, if a Market Participant enters a fuel price adjustment and simultaneously enters a new offer, the new offer must be within 10% of the Reference Level calculated based on the new fuel price. Third, a Market Participant that enters a fuel price adjustment must submit documentation verifying that the submitted fuel price is based on a fuel price quote, contract or price from an electronic trading system. A Market Participant that fails to submit verification will be excluded from submitting a fuel price adjustment for the applicable resource for a period of time.⁵¹

- The period for which mitigation applies, once triggered, is being made more flexible.⁵² Under the old rules, mitigation continued until the end of an Operating Day. Under the new rules, mitigation may end before the end of an Operating Day under appropriate conditions.
- Certain mitigation calculations are modified to reflect the potential variation in the period during which a resource may be mitigated.⁵³
- Modifying the local reliability commitment mitigation threshold so that it is only based on the existing 10% of low load cost threshold.⁵⁴ The current fixed \$80/MW threshold is eliminated because high and volatile fuel prices could result in mitigation being triggered inappropriately.⁵⁵
- The introduction of limits, based on fuel prices, to the amount that Start-Up Fees and No-Load Fees may be increased in real time.⁵⁶
- The elimination of the requirement that Market Participants with dual fuel resources submit offers based on the resource's least cost fuel so that these Market Participants can manage the delivery and price risk associated with natural

⁵⁰ *Id.* at pp. 9, 13-17.

⁵¹ *Id.* at p. 17.

⁵² *Id.* at pp. 18-20.

⁵³ *Id.* at pp. 18-21.

⁵⁴ *Id.* at pp. 5, 18.

⁵⁵ *Id.*

⁵⁶ *Id.* at pp. 21-22.

gas by offering based on oil costs and can conserve oil by offering based on natural gas costs.⁵⁷

More details about each of these changes are provided in the DePillis Testimony.

Self-Scheduling

Under the current market structure, a Market Participant self-schedules a generating resource by re-declaring the resource's Economic Minimum Limit to reflect the desired minimum output level of the resource.⁵⁸ From an operational perspective, this method has the disadvantage of reducing the resource's dispatchable range (*i.e.*, the difference between the resource's Economic Minimum Limit and Economic Maximum Limit).⁵⁹ In some conditions, the apparent reduction in a resource's dispatchable range from an operational perspective can artificially create excess generation conditions (also called a Minimum Generation Emergency) and require system operators to take administrative actions and/or implement administrative pricing to resolve the situation.⁶⁰

Under the Offer Flexibility Changes, a Market Participant will self-schedule a generating resource by submitting a request for a resource to be dispatched at a specific output level.⁶¹ If approved, the request will be accomplished by modifying the offer for the applicable energy Block of the resource to be equal to the Energy Offer Floor.⁶² As this method of self-scheduling does not modify the resource's Economic Minimum Limit, system operators may dispatch the resource to its Economic Minimum Limit before declaring a Minimum Generation Emergency.⁶³

Clarifying Changes

The Offer Flexibility Changes also include a number of changes intended to clarify the rules governing offers. The changes include the addition and deletion of some defined terms.⁶⁴ For example, the Offer Flexibility Changes adopt the use of the defined terms Energy Offer Floor, Energy Offer Cap, Minimum Run Time, Minimum Down Time and Reserve Adequacy Analysis for concepts that were less clearly described in the existing rules. As described in the Ethier/Parent Testimony, the Offer Flexibility

⁵⁷ *Id.* at pp. 22-23.

⁵⁸ Ethier/Parent Testimony at p. 6.

⁵⁹ *Id.* at pp. 14-15.

⁶⁰ *Id.*

⁶¹ *Id.* at pp. 13-14.

⁶² *Id.*

⁶³ *Id.* at pp. 14-17.

⁶⁴ *Id.* at pp. 20-21.

Changes also eliminate several obsolete terms and make a variety of clarifying changes to certain provisions.⁶⁵

VI. STAKEHOLDER PROCESS.

At its June 4-5, 2013 meeting, the NEPOOL Markets Committee voted to recommend that the NEPOOL Participants Committee support the Offer Flexibility Changes based on a show of hands, with one opposition and a number of abstentions recorded.⁶⁶ At its June 7, 2013 meeting, the Participants Committee voted to support the Offer Flexibility Changes with oppositions and abstentions noted.⁶⁷

VII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the Offer Flexibility Changes do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations.⁶⁸ Notwithstanding its request for waiver, the Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations:

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

- This transmittal letter;
- Blacklined ISO Tariff sections reflecting the revision submitted in this filing;
- Clean ISO Tariff sections reflecting the revision submitted in this filing;

⁶⁵ *Id.* at pp. 21-22.

⁶⁶ There were one opposition and two abstentions within the Generation Sector, two abstentions within the Transmission Sector, one abstention within the Supplier Sector, three abstentions within the Alternative Resources Sector, and two abstentions within the End User Sector.

⁶⁷ The Participants Committee approved the main motion to support the Offer Flexibility Changes, with oppositions noted by: CP Energy Marketing, Dominion Energy Marketing, and United Illuminating; and abstentions noted by: EquiPower Resources Management, Essential Power Massachusetts, Industrial Energy Consumer Group, Kimberly-Clark Corporation, Linde Energy Services, Maine Public Advocate Office, Maine Skiing, NextEra Energy Resources, NH Office of Consumer Advocate, NU/NSTAR, Praxair, and the AR Small Renewable Generation Group Member representative.

⁶⁸ 18 C.F.R. § 35.13 (2011).

- Testimony of Robert G. Ethier and Christopher A. Parent (the “Ethier/Parent Testimony”), sponsored solely by the ISO;
- Testimony of Mario S. DePillis, Jr. (the “DePillis Testimony”), sponsored solely by the ISO; and
- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent.

35.13(b)(2) – As set forth in Section II above, the Filing Parties request that the changes become effective on December 3, 2014.

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

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

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

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

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

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

35.13(c)(1) – The market rule change herein does not modify a traditional “rate,” and the statement required under this Commission regulation is not applicable to the instant filing.

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

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

VIII. CONCLUSION

For the reasons discussed in this transmittal letter and the accompanying testimony, the Filing Parties request that the Commission accept Offer Flexibility Changes to become effective on December 3, 2014.

Respectfully submitted,

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I.2 Rules of Construction; Definitions

I.2.1 Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

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

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

I.2.2. Definitions:

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

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

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

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

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

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

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

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

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

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

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

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

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

AGC is automatic generation control.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Asset Related Demand is a physical load that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of one or more

individual end-use metered customers receiving service from the same point or points of electrical supply, with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Bankruptcy Code is the United States Bankruptcy Code.

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

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

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

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

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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

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

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

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

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

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

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

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

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

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

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

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

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

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for the day); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy

(Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Commission is the Federal Energy Regulatory Commission.

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

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

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

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

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

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

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

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

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

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

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England

System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

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

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

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

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

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

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

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

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

Cost of New Entry (CONE) is the value that was determined by the ISO for each Forward Capacity Auction pursuant to the provisions of Section III.13 of Market Rule 1 in effect at the time of that auction.

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

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

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

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

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

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

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

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

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

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

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

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

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

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2017, Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts of a Demand Response Resource scheduled by the ISO as a result of the Day-Ahead Energy Market, multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1 and purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Demand Reduction Offer is an offer by a Market Participant with a Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

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

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

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

Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

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

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

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

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

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

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

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and the pumping load associated with pumped storage generators) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December,

and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

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

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

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

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

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

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

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

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

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

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

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

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

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

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

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the

Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

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

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

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Resources, change External Transactions, or change the status of a Dispatchable Asset Related Demand in accordance with the Resource's or contract's Supply Offer or Demand Bid parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

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

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

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance

with Dispatch Instructions and must meet the technical requirements specified in the ISO New England Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources, however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

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

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

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

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

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

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

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at prices of \$1.00/kW-month 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(a) for Resources with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for Resources without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Resource and with meeting all environmental regulations and licensing limits.~~

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

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

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

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

EMS is energy management system.

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

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

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

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II of the Tariff.

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

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

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

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

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

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

Energy Offer Floor is negative \$150/MWh.

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

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

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

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

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

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

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

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

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.

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

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service

obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

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

Governance Participant is defined in the Participants Agreement.

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

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

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

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

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

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

OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

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

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

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

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

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

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

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

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

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a

reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

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

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted

Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

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

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

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

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

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

ISO means ISO New England Inc.

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

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

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

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

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

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

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

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

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

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

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

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

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules,

procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Local Area Facilities are defined in the TOA.

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

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

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission

facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

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

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

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

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

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

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

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

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

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

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

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

Location is a Node, External Node, Load Zone or Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location also is a Dispatch Zone.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

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

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

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

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

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

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

LSE means load serving entity.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Measure Life is the estimated time a Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the Demand Reduction Value of the Demand Resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity

Commitment Period, and the Demand Reduction Value for an Existing Demand Resource is not overstated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in 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.13.2.8.1.1 of Market Rule 1.

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

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

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

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

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

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

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a

resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but does not have a winter audit value and a summer audit value.

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

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

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

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

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

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

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

NMPTC means Non-Market Participant Transmission Customer.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

NPCC is the Northeast Power Coordinating Council.

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

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2017. Demand Response Resources for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

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

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

Offered Full Reduction Time is the Demand Response Resource Notification Time plus the Demand Response Resource Start Up Time plus ((the Maximum Reduction minus the Minimum Reduction) divided by the Demand Response Resource Ramp Rate).

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

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

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

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

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

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

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

Operations Date is February 1, 2005.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority

for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Real-Time Commitment Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

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

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E1.8 for Capacity Commitment Periods commencing prior to June 1, 2017, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2017.

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

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

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

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

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

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when

deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as

Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

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

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

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

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

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

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

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

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

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

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

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

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, for Capacity Commitment Periods commencing on or after June 1, 2017, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in \$/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2017, a Demand Response Resource.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

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

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Self-Schedule is the action of a Market Participant in committing ~~and~~/or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing or scheduling a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been scheduled or dispatched by the ISO to provide the Energy. For a Dispatchable Asset Related Demand, Self-Schedule is the action of a Market Participant in committing or scheduling a Dispatchable Asset Related Demand to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the Dispatchable Asset Related Demand would have been scheduled or dispatched by the ISO to consume Energy.
Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to ~~the greater of:~~ (i) the Resource's Generator Asset's Economic Minimum Limit; ~~or~~ (ii) the Resource's Dispatchable Asset Related Demand's Minimum Consumption Limit; or (iii) for Regulation purposes with respect to a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

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

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, or Schedule 23 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock; (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) means the reserve capability of a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

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

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

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart O&M Payment is the annual compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

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

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

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

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

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

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

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

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

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

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

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered

into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Supplemental Availability Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: “Pre-scheduling” as specified in Section III.1.9, “Scheduling” as specified in III.1.10, and “Dispatch” as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 **[Reserved.]**

III.1.3.2 **[Reserved.]**

III.1.3.3 **[Reserved.]**

III.1.4 **Requirements for Certain Transactions.**

III.1.4.1 **ISO Settlement of Certain Transactions.**

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 **Transactions Subject to Requirements of Section III.1.4.**

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Supplemental Availability Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as “Section III.1.4 Transactions,” and individually as a “Section III.1.4 Transaction.” Transactions that conform to the standards are referred to collectively as “Section III.1.4 Conforming Transactions,” and individually as a “Section III.1.4 Conforming Transaction.”

III.1.4.3 **Requirements for Section III.1.4 Conforming Transactions.**

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a “Related Transaction”), where the Related Transaction:

- (i) is not cleared or settled by the ISO as Counterparty;
- (ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

- (iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and
 - (iv) is not contingent on either party to carry out the Section III.1.4 Transaction.
- (b) In addition, to qualify as a Section III.1.4 Conforming Transaction:
- (i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;
 - (ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and
 - (iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.
- (c) As further requirements:
- (i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and
 - (ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

- (a) Three types of Claimed Capability Audits may be performed:
 - (i) An Establish Claimed Capability Audit establishes the Generator Asset's ability to respond to ISO dispatch instructions and to maintain performance at a specified output level for a specified duration.

- (ii) A Seasonal Claimed Capability Audit determines a Generator Asset's capability to perform under specified summer and winter conditions for a specified duration.
- (iii) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value.
- (b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.
- (c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.
- (d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.
- (e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

- (a) The time and date of an Establish Claimed Capability Audit shall be unannounced.
- (b) For a newly commercial Generator Asset:
 - (i) An Establish Claimed Capability Audit will be scheduled by the ISO within seven Business Days of the commercial operation date for all Generator Assets except:
 1. Non-intermittent daily cycle or run of river hydro; and
 2. Intermittent, net-metered, or special qualifying facilities.
 - (ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
 - (iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.
- (c) For Generator Assets with an Establish Claimed Capability Audit value:
 - (i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.
 - (ii) An Establish Claimed Capability Audit shall be performed within seven Business Days of the date of the request.

- (iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
- (iv) The Establish Claimed Capability Audit values become effective seven Business Days following notification of the audit results to the Market Participant by the ISO.
- (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (d) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.
- (e) Establish Claimed Capability Audits shall be performed on Business Days between 0800 and 2200.
- (f) To conduct an Establish Claimed Capability Audit, the ISO shall:
 - (i) Notify the Designated Entity immediately prior to issuing the Dispatch Instruction that an audit will be conducted.
 - (ii) Ensure that the Generator Asset is Self-Scheduled for the time to ramp to its full capability and for the duration of the Establish Claimed Capability Audit.
 - (iii) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the asset's net output to increase from the current operating level to its Real-Time High Operating Limit.
 - (iv) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.
- (g) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit		
Unit Type	Summer Claimed Capability Audit Duration (Hrs)	Winter Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	4	4
Combined Cycle Total Unit, Integrated Coal Gasification Combustion Cycle, Pressurized Fluidized Bed Combustion	4	4
Combustion Gas Turbine	1	1

Internal Combustion Engine	1	1
Hydraulic Turbine – Reversible	4	2
Hydro-Conventional Weekly	2	2

III.1.5.1.3. Seasonal Claimed Capability Audits.

- (a) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:
 - (i) Intermittent, net-metered, and special qualifying facilities; and
 - (ii) Non-intermittent daily cycle and run of river hydro.
- (b) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset’s Seasonal Claimed Capability Audit obligation.
- (c) Except as provided in Section III.1.5.1.3(m) below, a summer Seasonal Claimed Capability Audit must be conducted:
 - (i) At least once every Capability Demonstration Year;
 - (ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.
- (d) A winter Seasonal Claimed Capability Audit must be conducted:
 - (i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:
 - (1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.
 - (2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.
 - (ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.
- (e) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:
 - (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the seventh Business Day following the day on which the audit concludes.

- (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.
- (f) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
- (g) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(c) and (d), the Seasonal Claimed Capability Audit value for the season shall be set to zero.
- (h) The Seasonal Claimed Capability Audit value shall become effective seven Business Days following notification of the audit results to the Market Participant by the ISO.
- (i) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit		
Unit Type	Summer Claimed Capability Audit Duration (Hrs)	Winter Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	2	2
Combined Cycle Total Unit, Integrated Coal Gasification Combustion Cycle, Pressurized Fluidized Bed Combustion	2	2
Combustion Gas Turbine	1	1
Internal Combustion Engine	1	1
Hydraulic Turbine-Reversible	2	2
Hydro-Conventional Weekly	2	2

- (j) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:
 - (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;
 - (ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

- (iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.
- (k) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) any time the temperature requirements were met at the Generator Asset's location the ISO denied the audit request, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:
 - (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;
 - (ii) Retain the current Seasonal Claimed Capability Audit value for the season; and
 - (iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.
- (l) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.
- (m) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:
 - (i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(e).

- (ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.
- (iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.
- (iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(c)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.
- (v) This Section III.1.5.1.3(m) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

III.1.5.1.4. ISO-Initiated Claimed Capacity Audits.

- (a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.
- (b) An ISO-Initiated Claimed Capability Audit value shall replace the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:
 - (i) The Establish Claimed Capability Audit values may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.
 - (ii) An ISO-Initiated Claimed Capability Audit value shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.
- (c) If a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.
- (d) Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective seven Business Days following notification of the audit results to the Market Participant by the ISO.
- (e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:
 - (i) Notify the Designated Entity, immediately prior to issuing the Dispatch Instruction, that an audit will be conducted.

- (ii) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset’s net output to increase from the current operating level to its Real-Time High Operating Limit.
 - (iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.
- (f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit		
Unit Type	Summer Claimed Capability Audit Duration (Hrs)	Winter Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	4	4
Combined Cycle Total Unit, Integrated Coal Gasification Combustion Cycle, Pressurized Fluidized Bed Combustion	4	4
Combustion Gas Turbine	1	1
Internal Combustion Engine	1	1
Hydraulic Turbine – Reversible	4	2
Hydro-Conventional Daily Pondage, Hydro-Conventional Run of River	2	2
Hydro-Conventional Weekly	2	2
Wind	2	2
Photovoltaic	2	2
Fuel Cell	2	2

III.1.5.2 ISO-Initiated Parameter Auditing.

- (a) The ISO may perform an audit of any Supply Offer parameter that impacts the ability of a Generator Asset to provide real-time energy or reserves.
- (b) Audits shall be performed using the following methods:

- (i) **Economic Maximum Limit.** The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.
 - (ii) **Manual Response Rate.** The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.
 - (iii) **Start-Up Time.** The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.
 - (iv) **Notification Time.** The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.
 - (v) **CLAIM10.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5 of Market Rule 1.
 - (vi) **CLAIM30.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5 of Market Rule 1.
 - (vii) **Automatic Response Rate.** The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second ISO-issued electronic Dispatch Instructions.
- (c) To Conduct an audit based upon historical data, the ISO shall:
 - (i) Obtain data through random sampling of generator performance in response to ISO Dispatch Instructions; or
 - (ii) Obtain data through continual monitoring of generator performance in response to ISO Dispatch Instructions.
 - (d) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset for the parameters being audited.
 - (e) To the extent that the audit results indicate a Market Participant is providing Supply Offer parameter values that are not representative of the actual capability of the Generator Asset, Supply Offer parameter values for the Generator Asset shall be restricted to the value that is supported by the audit.
 - (f) In the event that a Generator Asset has had a Supply Offer parameter value restricted:
 - (i) The Lead Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:
 1. Provide an explanation of the discrepancy;

2. Indicate the steps that the Market Participant will take to re-establish the Supply Offer parameter's value;
3. Indicate the timeline for completing the restoration; and
4. Explain the testing that the Market Participant will undertake to verify restoration of the Supply Offer parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the Supply Offer parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the Supply Offer parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.6 **[Reserved.]**

III.1.6.1 **[Reserved.]**

III.1.6.2 **[Reserved.]**

III.1.6.3 **[Reserved.]**

III.1.6.4 **ISO New England Manuals and ISO New England Administrative Procedures.**

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 **General.**

III.1.7.1 **Provision of Market Data to the Commission.**

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 **[Reserved.]**

III.1.7.3 **Agents.**

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 **[Reserved.]**

III.1.7.5 **[Reserved.]**

III.1.7.6 **Scheduling and Dispatching.**

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch.

(b) In the event that one or more Resources cannot be scheduled in the Day-Ahead Energy Market on the basis of a least-cost, security-constrained dispatch as a result of one or more Self-Schedule offers contributing to a transmission limit violation, the following scheduling protocols will apply:

(i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.

(ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers

will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.

(iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy bought and sold by the ISO in the New England Markets will reflect the hourly Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices in an hour caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices in an hour, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect the integrated hourly Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.10 Other Transactions.

(a) Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the obligations of Market Participants to make resources with a Capacity Supply Obligation available for dispatch by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

(b) [Reserved.]

(c) [Reserved.]

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

- (a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.
- (b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.
- (c) The Seasonal Claimed Capability of a Generator Asset is:
- (i) Based upon hydrology data for non-intermittent daily cycle and run of river hydro as described in Section III.13.1.2.2.2.
 - (ii) The median real power output during reliability hours for intermittent, net metered and special qualifying facilities, as reflected in hourly revenue metering data as described in Section III.13.1.2.2.2.
 - (iii) For all other Generator Assets, the minimum of: i) the Generator Asset's current Establish Claimed Capability Audit value and ii) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

III.1.7.12 [Reserved.]

III.1.7.13 **[Reserved.]**

III.1.7.14 **[Reserved.]**

III.1.7.15 **[Reserved.]**

III.1.7.16 **[Reserved.]**

III.1.7.17 **Operating Reserve.**

The ISO shall schedule to the Operating Reserve and load-following requirements of the New England Control Area and the New England Markets in scheduling Resources pursuant to this Market Rule 1. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 **Regulation.**

(a) Regulation shall be supplied from generators located within the metered electrical boundaries of the New England Control Area. Market Participants offering Regulation shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall obtain and maintain an amount of Regulation equal to the New England Control Area Regulation objective as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) The Regulation range of a unit shall be at least twice the amount of Regulation assigned and no less than the minimum specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(d) A unit that is providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided. The amount of Regulation provided by a unit shall serve to redefine the Economic Minimum Limit and Economic Maximum Limit of that unit, in that the amount of Regulation shall be added to the unit's Economic Minimum Limit or automatic low limit while regulating, whichever is greater, and subtracted from its Economic Maximum Limit or automatic high limit, whichever is less. Qualified Regulation must satisfy the verification tests described in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19 Ramping.

A generating unit dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the unit's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the ISO for that unit and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19A Real-Time Reserve.

(a) Real-Time TMSR, TMNSR, TMOR and Real-Time Replacement Reserve, if applicable, shall be supplied from Resources located within the metered boundaries of the New England Control Area subject to the condition set forth in Section III.1.7.19A(c) below. The ISO shall designate Operating Reserve in Real-Time only to Market Participant Resources that comply with the applicable standards and requirements for provision and dispatch of Operating Reserve capability as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and locational Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) External Resources will be permitted to participate in the Real-Time reserve market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO units that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output levels of generating units, or change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment is operated with control equipment functioning as specified in the ISO New England Manuals & ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market, along with Dispatch Rate levels above which it does not desire to purchase.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning generating Resources and Dispatchable Asset Related Demand Resources required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output for the pertinent Operating Day.

III.1.8 [Reserved.]

III.1.9 **Pre-scheduling.**

III.1.9.1 [Reserved.]

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 **Market Participant Responsibilities.**

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each generating unit as to which

the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline ~~specified in the ISO New England Manuals and ISO New England Administrative Procedures~~ and shall remain in effect ~~without change throughout each such period for which a specification was submitted~~ unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 **[Reserved.]**

III.1.10 **Scheduling.**

III.1.10.1 **General.**

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of generating Resources with notification time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers for such units, as submitted in accordance with Section 1.10.1A(f), for such periods and the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and such Resources shall be treated as Pool-Scheduled Resources and shall be eligible to receive NCPC Credits under Section III.3.2.3 in accordance with the binding Supply Offers submitted.

III.1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 10:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resource increments, including hydropower units, Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market

Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be ~~equal~~ ~~to or~~ greater than zero MW and shall not exceed the energy Supply Offer limitation specified in this Section.

(b) [Reserved.]

(c) All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the

offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to ~~\$0.0/MWh~~ the Energy Offer Floor; ~~and~~

(iv) If the sum of all submitted fixed External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all fixed External Transaction sales at the applicable External Node shall be set equal to ~~\$1,000/MWh~~ the Energy Offer Cap;

~~(v) _____ The ISO shall not consider Start-Up Fees, No-Load Fees, notification times or any other inter-temporal parameters in scheduling or dispatching External Transactions.~~

(d) Market Participants selling into the New England Markets, from either internal Resources or External Resources, shall submit Supply Offers or External Transactions for the supply of energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Regulation, Operating Reserve or other services as applicable, for the following Operating Day. ~~Supply Offers shall be submitted to the ISO in the form specified by the ISO and shall contain the information specified in the ISO's Offer Data specification, as applicable. External Transactions shall be submitted to the ISO according to Section III.1.10.7 of this Market Rule 1. The ISO shall not consider Start Up Fees, No Load Fee, notification times or any other inter-temporal parameters in scheduling or dispatching External Transactions.~~

Energy offered from generating Resources without a Capacity Supply Obligation shall not be supplied from Resources that are included in or otherwise committed to supply the operating reserve requirements of another Control Area. All Supply Offers and Demand Bids:

(i) Shall specify the Resource or Load Asset and energy for each hour ~~in of~~ the offer period ~~Operating Day;~~

(ii) Shall specify, for Supply Offers, Blocks (price and quantity of Energy) for each hour of the amounts and prices for the entire Operating Day for each Resource offered by the Market Participant to the ISO. The price and quantity values in a Block may each vary on an hourly basis;

(iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify, for Supply Offers, Start-Up Fees and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee values may vary on an hourly basis equal to the specification of such fees for such unit on file with the ISO (Market Participant changes to the Start Up Fee and No Load Fee can only occur during the open periodic bidding enrollment periods (daily));

(iv) ~~Shall set forth any special conditions upon which the Market Participant proposes to supply a Resource increment~~For a dual fuel Resource, shall specify, for Supply Offers, the fuel type. The fuel type value may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual fuel Resources in Section III.A.3 of Appendix A;

(v) Shall specify, for Supply Offers, a ~~minimum~~Minimum run ~~Run time~~Time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;

(vi) ~~Shall~~Supply Offers shall constitute an offer to submit the generating Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, ~~for a Self-Scheduled Resource, the Economic Minimum Limit may be revised to reflect the Self-Scheduled output level of the Resource and~~ for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect maximum energy available for the Operating Day, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;

(vii) Shall constitute, for Demand Bids, an offer to submit the Dispatchable Asset Related Demand Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes to the Maximum Consumption Limit and Minimum Consumption Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Minimum

Consumption Limit may ~~be revised~~ vary on an hourly basis to reflect the Self-Scheduled consumption level of the Resource;

(viii) Shall be final as to the price or prices at which the Market Participant proposes to supply or consume energy or other services to the New England Markets, such price or prices for Resources or portions of Resources scheduled in the Day-Ahead Energy Market being guaranteed by the Market Participant for the period extending through the end of the following Operating Day or, in the case of a generating Pool-Scheduled Resource continuing to run into the second Operating Day to satisfy its ~~minimum~~ Minimum run-Run timeTime, such price or prices being guaranteed by the Market Participant for the period extending into the second Operating Day that satisfies the Resource's ~~minimum~~ Minimum run-Run timeTime; and

(ix) Shall not specify an energy offer or bid price below ~~\$0/MWh~~ the Energy Offer Floor or above ~~\$1,000/MWh~~ the Energy Offer Cap.

(e) A Market Participant that wishes to make a Resource available to sell Regulation service shall submit a Supply Offer for Regulation, the price and quantity of which can vary on an hourly basis. The Supply Offer for Regulation that shall specify the Automatic Response Rate in megawatts per minute, the price in dollars per MWh of the Regulation capability being offered, such Regulation capability as calculated by the ISO by multiplying the submitted Automatic Response Rate by five minutes, and such other information specified by the ISO as may be necessary to evaluate the Supply Offer and the generating Resource's Regulation Opportunity Costs. The price of the Supply Offer shall not exceed \$100/MWh. Qualified Regulation capability must satisfy the verification tests specified in the ISO New England Manuals and ISO New England Administrative Procedures. Regulation capability amounts will be adjusted as necessary in the case where a generating unit's compliance rating is less than 90%. The audited Regulation capability will be deemed equal to the most recently calculated compliance rating times the 5-minute Regulation capability quantities utilized in that compliance rating calculation, rounded to the nearest whole megawatt. The Resource's Automatic Response Rate will then be adjusted based upon the audited Regulation capability.

(f) Each Market Participant owning or controlling the output of a resource with a Capacity Supply Obligation shall submit a forecast of the availability of each such resource for the next seven days. A Market Participant may submit a non-binding forecast of the price at which it expects to offer a generating Resource increment to the ISO over the next seven days.

(g) Each Supply Offer or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Resource and an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits and Economic Minimum Limits are not used in determining the amount of energy (MW) in each marginal Supply Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits and Economic Minimum Limits.

(j) In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers to sell energy in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy

Market as well as generators committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide energy in the Real-Time dispatch unless the schedules for such units are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy and related services, Start-Up Fees, No-Load Fees, and the specified operating characteristics, offered by Market Participants to the ISO by the offer deadline specified in Section III.1.10.1A.

(b) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

(c) Market Participants offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) The Market Participant seller whose Resource is selected as a Pool-Scheduled Resource shall receive payments or credits for energy or related services, or for Start-Up Fees and No-Load Fee, from the ISO on behalf of the Market Participant buyers in accordance with Section III.3 of this Market Rule 1. Additionally, the Market Participant seller shall receive for Pool-Scheduled Resources scheduled in the Real-Time Energy Market that were not scheduled in the Day-Ahead Energy Market, a pro-rata share of its applicable Start-Up Fee if the ISO cancels its selection of the Resource as a Pool-Scheduled Resource and so notifies the Market Participant seller before the Resource is synchronized (“Cancellation Fee”).

(e) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

(f) Eligibility for NCPC in the Day-Ahead Energy Market under Section III.3.2.3 is affected by Resource Self-Schedules. The specific rules related to the impact of Resource Self-Schedules on eligibility for NCPC may be found in *Appendix F* of this Market Rule 1.

(g) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 is affected by Resource Self-Schedules. The specific rules related to the impact of Resource Self-Schedules on eligibility for NCPC may be found in *Appendix F* of this Market Rule 1.

(h) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 may be affected by Resource trips. The specific rules related to the impact of Resource trips on eligibility for NCPC may be found in *Appendix F* of this Market Rule 1.

(i) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 is affected by ramping up in response to a start-up instruction and ramping down in response to a shutdown instruction. The specific rules related to the ramping impacts on eligibility for NCPC may be found in *Appendix F* of this Market Rule 1.

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled Resources shall be governed by the following principles and procedures.

(a) ~~{Reserved.}~~ The minimum duration of a Self-Schedule for a Generator Asset shall not result in the Generator Asset operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer.

(b) The offered prices of Resources or portions of Resources that are Self-Scheduled, or otherwise not following the dispatch orders of the ISO, shall not be considered by the ISO in determining Locational Marginal Prices.

(c) A Market Participant with a Resource that does not have a Capacity Supply Obligation shall comply with the requirements in Section III.13.6.2 when Self-Scheduling ~~any portion of~~ that Resource.

(d) A Market Participant Self-Scheduling a Resource in the Day-Ahead Energy Market that does not deliver the energy in the Real-Time Energy Market, shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.4 [Reserved.]

III.1.10.5 External Resources.

(a) Market Participants with External Resources that have dynamic scheduling and dispatch capability may submit Supply Offers to the New England Markets in accordance with the Day-Ahead and Real-Time scheduling processes specified above. Market Participants must submit Supply Offers for External Resources on a Resource specific basis. An External Resource with dynamic scheduling and dispatch capability selected as a Pool-Scheduled Resource shall be made available for scheduling and dispatch at the direction of the ISO and shall be compensated on the same basis as other Pool-Scheduled Resources.

(b) Supply Offers for External Resources with dynamic scheduling and dispatch capability shall specify the Resource being offered, along with the information specified in the Offer Data as applicable.

(c) For Resources external to the New England Control Area that are not capable of dynamic scheduling and dispatch, Market Participants shall submit External Transactions as detailed in Section III.1.10.7 of this Market Rule 1.

(d) A Market Participant whose External Resource is capable of dynamic scheduling and dispatch capability or whose External Transaction does not deliver the energy scheduled in the Day-Ahead Energy Market shall replace such energy not delivered as scheduled in the Day-Ahead Energy Market with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.6 Dispatchable Asset Related Demand Resources.

External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demand Resources. Except as noted below with respect to a pumped storage generator that does not have a Capacity Supply Obligation, a Dispatchable Asset Related Demand Resource in the New England Control Area must:

- (a) each day, either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy, unless and to the extent that the Dispatchable Asset Related Demand Resource is unable to do so due to an outage as defined in the ISO New England Manuals;
- (b) submit Demand Bid data that specifies a Maximum Consumption Limit and Minimum Consumption Limit;
- (c) submit Demand Bid data that specifies a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit;
- (d) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand Resource's ability to interrupt and the expected return date from the outage;
- (e) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;
- (f) abide by the ISO maintenance coordination procedures;
- (g) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand Resource; and
- (h) comply with the ISO New England Manuals.

To schedule the dispatchable pumping demand of a pumped storage generator that does not have a Capacity Supply Obligation, a Market Participant must comply with the requirements in (b) through (h) for the applicable Operating Day and must either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy for the applicable Operating Day.

III.1.10.7 External Transactions.

- (a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible

for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the applicable procedures governing the Emergency, as set forth in ISO New England Manual 11, require a change in schedule.

(d) A Market Participant submitting a priced External Transaction supporting Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must comply with the requirements in Section III.13.6.1.2.1 with respect to linking the transaction to the associated transmission reservation and NERC E-Tag. All other External Transactions submitted to the Real-Time Energy Market must contain the associated NERC E-Tag and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) All Real-Time External Transactions shall be scheduled and curtailed in accordance with the ISO New England Manuals and all applicable tariffs.

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

- (2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;
 - (3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;
 - (4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;
 - (5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.
- (g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.
- (i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.
 - (ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.
 - (iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer

Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) Day-Ahead NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.5.

(ii) Real-Time NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.16.

(iii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iv) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New

England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.8 ISO Responsibilities.

(a) The ISO shall use its best efforts to determine (i) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market. In making these determinations, the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post

the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Pool-Scheduled Resources and to direct that schedules be changed in an Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to generation Supply Offers and revisions to Demand Bids for any Dispatchable Asset Related Demand Resource. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) ~~A Market Participant may adjust the schedule of a Resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the ISO is notified not later than 20 minutes prior to the hour as follows:~~

~~(i) A Market Participant may Self-Schedule any of its Resources consistent with the ISO New England Manuals and ISO New England Administrative Procedures;~~

~~(ii) [Reserved]; or~~

~~(iii) [Reserved]; or~~

~~(iv) — A Market Participant may remove from service a Resource increment previously designated as Self-Scheduled consistent with the ISO New England Manuals and ISO New England Administrative Procedures. Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:~~

~~(i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual fuel Resources), the quantity and price pairs of its Blocks, and the Supply Offer for Regulation may be modified.~~

~~(ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.~~

(c) During the Re-Offer Period, Market Participants may submit revisions to priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may at any time, consistent with the provisions in Manual 11, request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect.

~~(d) **[Reserved.]** During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit.~~

~~(e) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(b), then:~~

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched as though it had offered for the hour in question at a Self-Scheduled MW.

(ef) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output.

The ISO shall have the authority to direct any Market Participant to adjust the output of any Pool-Scheduled Resource increment within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources, subject to an obligation to pay any applicable Start-Up Fees, No-Load Fee, or Cancellation Fees. The ISO shall adjust the output of Pool-Scheduled Resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (c) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Pool-dispatched Resources.

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Pool-Scheduled Resource increments and the designation of Real-Time Operating Reserve to Pool-Scheduled Resource increments, including the dispatchable increments from resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall ensure that the entity controlling a Pool-Scheduled Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified. During each hour of any tests performed under Section III.1.11.3(c),(i), the Resources under test shall be considered Self-Scheduled Resources for the purposes of calculating NCPC Credits. Procedures related to the ISO's modification of operational related Offer Data and Market Participant requests for testing shall be as defined in the ISO New England Manuals.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to dispatched output levels as practical, consistent with Good Utility Practice.

(e) Wind resources are treated as not economically dispatchable until the ISO is technically capable of determining and telemetering a Do Not Exceed Dispatch Point to the resource.

(f) The ISO may request that dual-fueled generating Resources that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fueled units that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fueled units that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 Regulation.

(a) A Market Participant may satisfy its Regulation obligation from its own Resources capable of performing Regulation service or by purchases from the ISO through the New England Markets at the rates set forth in Section III.3.2.2.

(b) The ISO shall obtain Regulation service from the least-cost alternatives available from either Pool-Scheduled Resources or Self-Scheduled Resources as needed to meet New England Control Area requirements not otherwise satisfied by the Market Participants. The ISO assigns Regulation to eligible generating units using the ISO Regulation assessment software. The Regulation assessment software calculates, at five minutes after the hour and on demand as needed, the optimal set of generating units required to meet the Regulation Requirement. The software first calculates a Regulation Rank Price, based on estimates of Time-on-Regulation Credits, Regulation Service Credits, estimated Regulation

Opportunity Costs, Regulation Capability and other factors, as specified below, that consider the impact of Regulation assignment on the Real-Time Energy Market. An interim clearing price is then calculated and the Regulation Rank Prices are updated using this interim clearing price to recognize that actual payments for Regulation are based upon the Regulation Clearing Price and not the Regulation offer price. The software continues to iterate in this manner until convergence is reached, resulting in an optimal selection of generating units for Regulation assignment. The ISO utilizes the output from this software when evaluating the set of generating units for Regulation assignment. In the event that one or more generating units to be selected have equal Regulation Rank Prices, the ISO shall select the generating unit for Regulation assignment with the largest Regulation Capability. Details of the process and calculations are described below.

(1) At the start of each operating hour, the ISO calculates an initial Regulation Rank Price for each eligible unit offering to provide Regulation using the ISO's Regulation assignment software. The initial Regulation Rank Price for each unit is equal to the sum of the following calculations divided by that unit's Regulation Capability:

(a) Time-on-Regulation Credit estimate calculated as the product of the Regulation Capability times the Regulation offer price;

(b) Regulation Service Credit estimate is set equal to the Time-on-Regulation Credit estimate to meet the 50/50 revenue mix objective as determined by the ISO in accordance with procedures specified in the ISO New England Manuals and ISO New England Administrative Procedures;

(c) Regulation Opportunity Cost estimate calculated as the product of the opportunity cost MW times the opportunity cost price differential where:

(i) Opportunity cost MW is calculated as the absolute value of the difference between the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by Economic Max and Economic Min, and EstRegGen.

(ii) EstRegGen is the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by RSETHI and RSETLO. RSETHI is equal to the Regulation

High Limit – Regulation Capability. RSETLO is equal to the Regulation Low Limit + Regulation Capability.

(iii) To more accurately estimate the actual Regulation Opportunity Cost, EstRegGen is further constrained as follows to account for units with large regulating ranges and slow response rates: if actual generation is less than EstRegGen and EstRegGen is greater than RSETLO, then EstRegGen is constrained up by the greater of (actual output + (SlowWideTime * Automatic Response Rate)) and RSETLO; if actual generation is greater than EstRegGen and EstRegGen is less than RSETHI, then EstRegGen is constrained down by the lesser of (actual output – (SlowWideTime * Automatic Response Rate)) and RSETHI. The SlowWideTime is determined by the ISO based upon empirical studies. The initial SlowWideTime value, and subsequent updates, shall be posted on the ISO's website.

(iv) Opportunity cost price differential is calculated as the absolute value of the difference between the average offer price of the opportunity MW and the Real-Time nodal LMP of the unit.

(d) Lookahead penalty estimate. The lookahead calculation assigns a cost penalty to units in the selection process if there is a change in energy offer prices near EstRegGen. It is calculated as 0.17 multiplied by the greater of:

(i) the unit's energy offer price at a higher output level (LookupRegGen as defined below) minus its energy offer price at EstRegGen, multiplied by (LookupRegGen – EstRegGen);
and

(ii) the unit's energy offer price at EstRegGen minus its energy offer price at a lower output level (LookdownRegGen as defined below), multiplied by (EstRegGen -LookdownRegGen),
where,

LookupRegGen = (EstRegGen + (LookAheadMinutesUp * Automatic Response Rate)) as bounded by Regulation High Limit; and LookdownRegGen = (EstRegGen – (LookAheadMinutesDown * Automatic Response Rate) as bounded by Regulation Low Limit),
And where the initial values of LookAheadMinutesUp and LookAheadMinutesDown, and subsequent updates, will be posted on the ISO's website.

(e) A tiebreaker adder is calculated for both pool-scheduled and Self-Scheduled Regulation units. The tiebreaker adder is equal to a tiebreaker multiplier (.000001) times the difference between a tiebreaker megawatt reference value (500 MW) and the Regulation Capability of the unit.

For Self-Scheduled Regulation, all values calculated under this Section III.1.11.5(b)(1) are set equal to zero except for the tiebreaker adder.

(2) The ISO's Regulation assignment software creates an initial merit order stack of eligible Regulation Capability by sorting the generating units by the initial Regulation Rank Prices calculated under Section III.1.11.5 (b)(1) in ascending order. Generating units are then selected in rank order until the Regulation Requirement is met. An initial clearing price is then calculated based upon the highest Regulation offer price associated with the initial set of generating units selected to meet the Regulation Requirement. Updated Regulation Rank Prices are then recalculated for generating units with Regulation offer prices that are less than the initial clearing price by substituting the initial clearing price for the generating unit's Regulation offer price, recalculating the Time-On-Regulation Credit and the Regulation Service Credit estimates; adding the originally calculated values under Sections III.1.11.5(b)(1)(c), (d) and (e) to these recalculated values and dividing this total by the unit's Regulation Capability. These updated Regulation Rank Prices are utilized along with the initial Regulation offer prices adjusted to include opportunity costs that are greater than or equal to the initial clearing price to create an updated generating unit list sorted by ascending Regulation Rank Prices. An updated clearing price is then calculated and the software continues to iterate in this manner until convergence is reached producing an optimal generating unit rank order list for use in assigning Regulation.

(3) Shortly after the start of an hour and during the hour as needed, the ISO updates the generating unit rank order list using the ISO's Regulation assignment software based on any changes to Regulation Capability eligibility and other current information, including any changes to Self-Schedule Regulation. The ISO uses this updated Regulation rank order list to assign Regulation for the upcoming hour and to make changes to Regulation assignments within the hour.

(c) The ISO shall dispatch Resources for Regulation by sending Regulation signals and instructions to Resources from which Market Participants, in accordance with the ISO New England Manuals and ISO

New England Administrative Procedures, have offered Regulation service. Market Participants shall comply with Regulation dispatch signals and instructions transmitted by the ISO and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources supplying load in the New England Control Area as close to desired output levels as practical, consistent with Good Utility Practice.

III.1.11.6 **[Reserved]**

III.1.12 **Dynamic Scheduling.**

Dynamic scheduling can be requested and may be implemented in accordance with the following procedures:

- (a) An entity that owns or controls a generating Resource in the New England Control Area may electrically remove all or part of the generating Resource's output from the New England Control Area through dynamic scheduling of the output to load outside the New England Control Area. Such output shall not be available for economic dispatch by the ISO.

- (b) An entity that owns or controls a generating Resource outside of the New England Control Area may electrically include all or part of the generating Resource's output into the New England Control Area through dynamic scheduling of the output to load inside the New England Control Area. Such output shall be available for economic dispatch by the ISO.

- (c) An entity requesting dynamic scheduling shall be responsible for arranging for the provision of signal processing and communication from the generating unit and other participating Control Area and complying with any other procedures established by the ISO regarding dynamic scheduling as set forth in the ISO New England Manuals. Allocation of costs associated with dynamic scheduling shall be determined and filed with the Commission following the first request.

- (d) An entity requesting dynamic scheduling shall be responsible for reserving amounts of appropriate transmission service necessary to deliver the range of the dynamic transfer and any ancillary services.

III.2 LMPs and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of generation supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area,

transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.4, every offer of energy by a Market Participant from a generating Resource, an External Transaction purchase Resource and a Dispatchable Asset Related Demand Resource that is following economic dispatch instructions of the ISO will be utilized in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and locational Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the most recent power flow solution produced by the State Estimator, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission

line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Determination of Energy Offers Used in Calculating Real-Time Prices and Real-Time Reserve Clearing Prices.

(a) During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market.

(b) To determine the energy offers submitted to the New England Markets that shall be used during the Operating Day to calculate the Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall determine which generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources are following its economic dispatch instructions. A generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-Time Prices if:

(i) the applicable Supply Offer price submitted by a Market Participant for energy from the generating Resource or External Transaction purchase is less than or equal to the Dispatch Rate associated with that generating Resource or External Transaction purchase; and

(ii) the applicable Demand Bid price submitted by a Market Participant for energy from the Dispatchable Asset Related Demand Resource is greater than or equal to the Dispatch Rate associated with that Dispatchable Asset Related Demand Resource; and

(iii) the generating Resource, other than a Fast Start Generator, is operating above its Economic Minimum Limit; or

(iv) the Fast Start Generator is operating at or above its Economic Minimum Limit and the applicable Supply Offer price submitted by a Market Participant for energy from the Fast Start Generator is less than or equal to the Dispatch Rate associated with that Fast Start Generator; or

(v) the generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource is specifically requested to operate or reduce consumption by the ISO's dispatcher and the associated energy offers or bids submitted are otherwise eligible to be included in the calculation of Real-Time Locational Marginal Prices.

(c) In determining whether a generating Resource or External Transaction purchase satisfies the condition described in III.2.4(b), the ISO will determine the Supply Offer price associated with an energy offer by comparing the actual megawatt output of the generating unit or External Transaction purchase with the Market Participant's Supply Offer price curve for that generating unit or External Transaction purchase. Because of practical generator response limitations, a generating unit whose megawatt output is not more than ten percent above the megawatt level specified in the Supply Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

(d) In determining whether a Dispatchable Asset Related Demand Resource satisfies the condition described in III.2.4(b), the ISO will determine the Demand Bid price associated with a Demand Bid by comparing the actual megawatt consumption of the Dispatchable Asset Related Demand Resource with the Market Participant's Demand Bid price curve for that Dispatchable Asset Related Demand Resource. Because of practical Dispatchable Asset Related Demand Resource response limitations, a Dispatchable Asset Related Demand Resource whose megawatt consumption is greater than or equal to ninety percent of the megawatt level specified in the Demand Bid price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy demand bid price used in the calculation of Real-Time Prices shall not be lower than the applicable Dispatch Rate.

III.2.5 Calculation of Real-Time Nodal Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section

III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.8; and (5) the effect on transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed every five minutes, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5. shall be set equal to ~~zero~~ the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes if the Minimum Generation Emergency was declared on a New England Control Area wide basis or shall be set equal to ~~zero~~ the Energy Offer Floor for all Nodes and External Nodes within a sub-region if the Minimum Generation Emergency was declared within the sub-region.

III.2.6 Calculation of Day-Ahead Nodal Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions

resulting from the load specifications submitted by Market Participants, Supply Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying a linear optimization method to minimize energy, congestion and transmission loss costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer or bid as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Node.

The process for clearing External Nodes differs from the process for clearing other Nodes in that, in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available generation at its Economic Maximum Limit, the technical

software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction sales are considered to be dispatchable at \$1,000/MWh the Energy Offer Cap;

(ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer or Increment Offer price cleared). Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line generation, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line generation, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

(c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide generation MW (including fixed External Transaction purchases) with all possible generation off and with all remaining generation at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic generation in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction purchases are considered to be dispatchable at \$0/MWh the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed generation down proportionately by ratio of Economic Minimum Limits but not below Emergency Minimum Limits. If power balance is achieved prior to reaching Emergency Minimum Limits, set LMP values equal to the lowest offer price of all on-line generation; and

(iii) If power balance not achieved in step (ii), set LMP values to ~~zero~~ Energy Offer Floor and reduce all committed generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.

(a) The ISO shall calculate Zonal Prices for each Load Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets for each hour using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

(b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.

(c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.

(d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.

(e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.

(f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.

(g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones and Reserve Zones and add or subtract Reliability Regions, Load Zones and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency

response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

(h) In the event the ISO makes changes to a Reliability Region or Load Zone or adds or subtracts Reliability Regions and Load Zones, for settlement purposes and to the extent practicable, Load Assets that are physically located in one Reliability Region and electrically located within another Reliability Region shall be located within the Reliability Region to which they are electrically located.

(i) External Nodes are the nodes at which External Transactions settle. As appropriate and after consulting with Market Participants, the ISO will establish and re-configure External Nodes taking into consideration appropriate factors, which may include: tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices, and inter-regional trading impacts.

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer's knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer's company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer's annual load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require

customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of Real-Time Nodal Prices specified under Section III.2.5, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available generating Resources and Dispatchable Asset Related Demand Resources with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMSNR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve or local TMOR, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all generating Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The unit-specific Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a generating Resource shall be determined for each generating Resource that the ISO requires to reduce output in order to provide additional Operating Reserve or local TMOR and shall be equal to the difference between (i) the Real-Time Energy LMP at the generation

Node for the generating Resource and (ii) the offer price associated with the reduction of the generating Resource's output necessary to create the additional Operating Reserve or local TMOR from the generating Resource's expected output level if it had been dispatched in economic merit order.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the LP algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

<u>Requirement</u>	<u>Requirement Sub-Category</u>	<u>RCPF</u>
Local TMOR		\$250/MWh
System TMOR	minimum TMOR	\$500/MWh
	Replacement Reserve	\$250/MWh
System TMNSR		\$850/MWh
System TMSR		\$50/MWh

The RCPFs shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve Requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed every five minutes, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour to be used in settlements.

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes within the New England Control Area, which Nodes shall be identified by the ISO on its internet website. The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

- (i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;
- (ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;
- (iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;
- (iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and
- (v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.

(b) The ISO shall calculate and publish hourly Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation Clearing Prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices as soon as practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve

Clearing Prices and final Regulation Clearing Prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the

applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

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

III.A.1.4. Interpretation.

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

III.A.1.5. Definitions.

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

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

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

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

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

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

- (b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.
- (c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

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

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

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

- (b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of this *Appendix A*, in accordance with the provisions of Section III.A.17 of this *Appendix A*.
- (c) Conduct evaluations and prepare reports on its own initiative or at the request of others.
- (d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this *Appendix A*.
- (f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.
- (g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this *Appendix A*, as appropriate.
- (h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

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

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

- (a) Maintain *Appendix A* and consider whether *Appendix A* requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.
- (b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this *Appendix A*.
- (c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this *Appendix A*.
- (d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this *Appendix A*.
- (e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.
- (g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this *Appendix A*.

- (h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.
- (i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this *Appendix A*.
- (j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this *Appendix A* are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:
 - (i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.
 - (ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.
 - (iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this *Appendix A*.
 - (iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this *Appendix A*.

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

- (k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:
 - (i) Anti-competitive gaming of Resources;
 - (ii) Conduct and market outcomes that are inconsistent with competitive markets;
 - (iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;
 - (iv) Actions in one market that affect price in another market;
 - (v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this *Appendix A*, interfere with efficient market operation, both short-run and long-run; and
 - (vi) Rules or conduct that creates barriers to entry into a market.

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

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

information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

- (m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with *Appendix B* of this Market Rule 1.
- (n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

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

III.A.2.4.1. Purpose.

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

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

- (a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11. below:
- (b) Notwithstanding the foregoing or any other provision of this *Appendix A*, and as more fully described in Section III.B.3.2.6 of *Appendix B* to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3 Applicability.

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

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

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

III.A.2.4.5 Duration of Mitigation.

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

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant. In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Market

~~Participant requests to alter a Reference Level must be submitted to imm@iso-ne.com Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.~~

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this *Appendix A*, the Market Participant may contact the Internal Market Monitor to provide an explanation of increased cost. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor ~~no later than 90 minutes after the submission deadline for~~ at least one hour prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor ~~no later than 30 minutes after~~ at least one hour prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment analyses if received by 6:00 p.m. the day prior to the Operating Day. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. ~~A Market Participant request pursuant to this section must be submitted to imm@iso-ne.com~~ Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market Participant's submission of the offer.

Any changes to fuel prices shall not be subject to the consultation provisions of this Section III.A.3.1. If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this *Appendix A* for dual fuel Resources, the Internal Market Monitor shall utilize the ~~least cost~~ fuel type specified in the Supply Offer for ~~in~~ the calculation of cost-based Reference Levels pursuant to Section III.A.7.5 below. If a Market Participant ~~requests that the Internal Market Monitor use a higher cost fuel type in the calculation of the cost based Reference Level, then it~~

~~must specify a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher priced fuel available to the Resource, then within five business days the Market Participant must:~~

~~(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel and expected duration of such use. The verification as to cause must include a statement as to how the use of the higher cost fuel is consistent with ensuring the availability of the Resource.~~

~~(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.~~

~~In the event that:~~

~~(a) the lower cost fuel becomes physically unavailable after the offer deadline for the Operating Day;~~

~~(b) the offer for the Operating Day is at or below the Reference Level based on the higher cost fuel, and;~~

~~(c) the Market Participant notifies the Internal Market Monitor; then~~

~~the Internal Market Monitor shall evaluate the information provided by the Market Participant. If the Internal Market Monitor determines that the Reference Level should be based on the more expensive fuel, the Internal Market Monitor may apply a Reference Level based on the more expensive fuel, or treat the offer as not violating applicable conduct tests for the Operating Day for which the offer is submitted. At the time of notification, the Market Participant shall provide all available documentation showing why the Resource must use the higher priced fuel, such as a fuel supplier notice of the interruption. Within five business days of the Operating Day, if not already made available to the Internal Market Monitor during the initial notification, the Market Participant shall provide full documentation regarding the use of the higher priced fuel, including evidence that the higher priced fuel was used or, alternatively, of the lack of energy generated, as well as evidence of the fuel interruption.~~

If the Market Participant fails to provide supporting information within five business days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes. ~~Market Participant requests and supporting information must be submitted to imm@iso-ne.com.~~

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. The Reference Levels will be made available on a daily basis. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline.

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus \$2.50/MMBtu.

(b) Within five business days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with (i) an invoice for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price may be no greater than 110% of the fuel price reflected on the submitted invoice for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder.

(c) The Supply Offers for the associated Resource may be no greater than 110% and no less than 90% of the Reference Level calculated with the submitted fuel price.

(d) If, within a 12 month period, the requirements in sub-sections (b) or (c) are not met for a Resource, then a fuel price adjustment shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-sections (b) or (c) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

<u>Number of Incidents</u>	<u>Months Precluded (starting from most-recent incident)</u>
<u>1</u>	<u>2</u>
<u>2 or more</u>	<u>6</u>

III.A.4. Physical Withholding.

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

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

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

Physical withholding may include, but is not limited to:

- (a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
- (b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,

- (c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
- (d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

- (a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
- (b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or
- (c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

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

III.A.4.2.3. Withholding of Transmission.

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

III.A.4.2.4. Resources in Congestion Areas.

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

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

- (a) all Supply Offer parameters shall be reviewed for economic withholding;
- (b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;
- (c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five business days prior to the start of

the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

- (a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 “General Threshold Energy Mitigation” and Section III.A.5.5.3 “General Threshold Commitment Mitigation” apply, and;
- (b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 “Constrained Area Threshold Energy Mitigation” and Section III.A.5.5.4 “Constrained Area Threshold Commitment Mitigation” apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval in the Day-Ahead Energy Market is any of the 24 hours for which pivotal supplier calculations are made. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to the clearing of the Day-Ahead Energy Market, prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

- (a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;
- (b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than \$25/MWh.

III.A.5.3. Calculation of Impact Tests in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.1 "General Threshold Energy Mitigation" compares two LMPs at a Resource's Node. The first LMP is calculated based on the Supply Offers submitted for all Resources. The second LMP is calculated through a simulation of the Day-Ahead Energy Market with the offer blocks associated with conduct violations of the pivotal supplier's Resources set to their Reference Levels.

A Supply Offer shall be determined to have no price impact for the purposes of Section III.A.5.5.1 "General Threshold Energy Mitigation" if:

- (a) the first LMP at the Resource's Node is less than the impact threshold, or;
- (b) the first LMP minus the Resource's Reference Level for each offer block is less than the impact threshold.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

- (a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
- (b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers submitted by a Lead Market Participant that is determined to be a pivotal supplier.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or \$100/MWh, whichever is lower. Offer block prices below \$25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or \$100/MWh, whichever is lower as determined by the day-ahead or real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or \$25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or \$25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. General Threshold Commitment Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource whose Lead Market Participant is determined to be a pivotal supplier.

III.A.5.5.3.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if any Start-Up Fee or No-Load Fee exceeds the Reference Level for that fee by 200% or more.

III.A.5.5.3.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters of its Supply Offer set to their Reference Levels, including all offer blocks and all types of Start-Up Fees and the No-Load Fee.

If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.4. Constrained Area Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if any Start-Up Fee or the No-Load Fee is submitted with an increase greater than 25% above the Reference Level.

III.A.5.5.4.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all energy offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Local Reliability Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are committed to provide, or Resources that are required to remain online to provide, one or more of the following:

- (a) local first contingency protection or local second contingency protections;
- (b) VAR or voltage support; or
- (c) Special Constraint Resource Service

III.A.5.5.5.2. Conduct Test.

All financial parameters of Supply Offers will be evaluated to determine whether the following formula is true:

$$(\text{Low Load Cost at Offer} - \text{Low Load Cost at Reference Level}) = < \text{Commitment Cost Threshold}$$

Where,

Commitment Cost Threshold = ~~the lower of (0.1 times Low Load Cost at Reference Level) or (\$80 multiplied by the Resource's Economic Maximum).~~

Low Load Cost = the cost of operating the Resource at Economic Minimum calculated using the following formula:

$$(\text{Cold Start-Up Fee} + (\text{No Load Fee} * \text{minimum run time}) + (\text{Price of Energy at Economic Minimum} * \text{Economic Minimum} * \text{minimum run time}))$$

Low Load Cost at Offer = Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level = Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

Price of Energy at Economic Minimum = the price for energy at the Resource's Economic Minimum.

For Low Load Cost at Offer, the price for energy is the price from the Supply Offer. For Low Load Cost at Reference Level, the Reference Level of the offer block at Economic Minimum is used.

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

If the (Low Load Cost at Offer – Low Load Cost at Reference Level) is greater than the Commitment Cost Threshold, then the conduct test is violated.

III.A.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 “General Threshold Energy Mitigation” or III.A.5.5.2 “Constrained Area Threshold Energy Mitigation” is in effect for the following duration:

- (a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which;
 - (i) for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,
 - ~~(a)(ii) for constrained area energy mitigation, the Resource is not located within a constrained area.~~
- (b) in the Day-Ahead Energy Market, mitigation ~~starts at the beginning of the Operating Day; and, is in effect in each hour in which the impact test is violated.~~
- ~~(c) for both the Real-Time Energy Market and Day-Ahead Energy Market, mitigation remains in effect through the end of the Operating Day or through the end of the Resource’s minimum run time, whichever is later.~~

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.3 “General Threshold Commitment Mitigation”, III.A.5.5.4 “Constrained Area Commitment Mitigation”, or III.A.5.5.5 “Local Reliability Commitment Mitigation” is in effect for the following duration:

- (a) in the Real-Time Energy Market, mitigation starts either;
 - a. on the first hour a Resource is directed to remain on-line by the ISO or;
 - b. in all other cases, at the time of the decision to commit the Resource.
- (b) in the Day-Ahead Energy Market, mitigation starts at the beginning of the Operating Day, and;
- (c) for both the Real-Time Energy Market and Day-Ahead Energy Market, mitigation remains in effect;
 - (i) for mitigation imposed pursuant to Sections III.A.5.5.3 or III.A.5.5.4, through the end of the Operating Day or through the end of the Resource’s ~~minimum~~ Minimum Run Time; and,

(ii) for mitigation imposed pursuant to Section III.A.5.5.5, through the end of the Resource's Minimum Run Time or through the end of the period that the Resource is needed for reliability,
whichever is later.

III.A.5.8. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five business days of the applicable Operating Day. The ISO shall correct the error as part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.9. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., minimum run time, minimum down time, start time, and notification time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up

state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.1.1. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

- (a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.
- (b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.

- (c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Supply Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of a Supply Offer according to the following hierarchy, under which the first method that can be calculated is used:

- (a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
- (b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
- (c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

- (a) The cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
- (b) The Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
- (c) The Lead Market Participant requests the cost-based Reference Level.
- (d) During the previous 90 days:
 - (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
 - (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy

Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.

(iii) The Market Participant submits a fuel price pursuant to Section III.A.3.4.

For the purposes of this subsection:

- i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.
- ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.
- iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.
- iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar days (weekday or weekend day), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant through the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

- (a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 “Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources”.
- (b) Costs must be documented.
- (c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible.
- (d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.
- (e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

 - (i) Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and
 - (e)(ii) Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor’s determination of a Resource’s marginal costs shall include an assessment of the Resource’s incremental operating costs in accordance with the following formulas,

Incremental Energy:

$(\text{incremental heat rate} * \text{fuel costs}) + (\text{emissions rate} * \text{emissions allowance price}) + \text{variable operating and maintenance costs} + \text{opportunity costs}.$

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

- (a) emissions limits;
- (b) water storage limits; and,
- (c) other operating permits that limit production of energy.

No-Load:

(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up:

(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. Determination of Offer Competitiveness During Shortage Event.

The Internal Market Monitor shall evaluate the competitiveness of the Supply Offer of each Resource with a Capacity Supply Obligation that is off-line during a Shortage Event, as described below. The evaluation for competitiveness shall be performed on Supply Offers in the Day-Ahead Energy Market and 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 Sections III.A.5.5.1 and III.A.5.5.3 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 Sections III.A.5.5.2 and III.A.5.5.4.
- (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 Fees 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.8 (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.8 (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.9. Regulation.

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

III.A.10. Demand Bids.

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

- (a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.
- (b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.
- (c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The

average percentage will be computed over a specified time period determined by the Internal Market Monitor.

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

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

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

$$(\text{LMP}_{\text{real time}} / \text{LMP}_{\text{day ahead}}) - 1.$$

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

III.A.11.3. Mitigation Measures.

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

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

- (i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.
- (ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.
- (iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

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

III.A.12. Cap on FTR Revenues.

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

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

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

- (a) [Reserved].
- (b) Section III.13.1.2.2.5.2 "Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity."
- (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.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

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

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

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

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this *Appendix A*. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

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

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.

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

determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Filing Right.

If either (a) as a result of mitigation applied to a Resource under this *Appendix A* for all or part of one or more Operating Days, or (b) in the absence of mitigation, despite having submitted a Supply Offer at the energy offer cap specified in Section III.1.10.1.A(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 the duration of the mitigation event~~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.15.2. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource for the Operating Days~~duration of the mitigation event~~ exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource for the duration of the mitigation event~~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.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.

III.A.15.4. Cost Allocation.

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

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

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

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

III.A.16.2. Standard of Review.

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

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

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

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

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

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

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

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this *Appendix A* and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market

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

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this *Appendix A*.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government

agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.

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

- (i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.
- (ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.
- (iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.
- (iv) Review and assessment of the effectiveness of *Appendix A* and the administration of *Appendix A* by the Internal Market Monitor for consistency and compliance with the terms of *Appendix A*.
- (v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

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

report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

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

- (a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;
- (b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;
- (c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,
- (d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

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

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten business days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy.

Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

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

III.A.18.2. Additional Ethical Conduct Standards.

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

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

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

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of *Appendix A*, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

- (A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.
- (B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information
 - (1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);

- (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
 - (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
 - (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
 - (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;
 - (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
 - (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

- (A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.
- (B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

- (C) The referral should be addressed to the Commission’s Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information.
- (1) A detailed narrative describing the perceived market design flaw(s);
 - (2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;
 - (3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;
 - (4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21 Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1 Offer Review Trigger Prices.

For each new resource type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3 or III.13.1.4.2.4 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1 Offer Review Trigger Prices for the Eighth Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the eighth

Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017) shall be as follows:

Resource Type	Offer Review Trigger Price (\$/kW-month)
Combustine Turbine	\$10.00
Combined Cycle Gas Turbine	\$11.00
Biomass	\$24.00
On-Shore Wind	\$14.00
Real-Time Demand Response	\$1.00
Energy Efficiency	\$0.00
All Other Resource Types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different resource types, the resource shall have an Offer Review Trigger Price equal to the highest of the applicable Offer Review Trigger Prices.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability, the Offer Review Trigger Prices in the table above shall apply, based on the resource type of the External Resource. For any other New Import Capacity Resource, the Offer Review Trigger Price shall be \$0.00/kW-month.

III.A.21.1.2 Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the resource types listed above shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For new generation resources, the methodology used to develop the Offer Review Trigger Price is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model, rounded to the nearest whole dollar value. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm’s length between two unrelated parties).

(c) For new energy efficiency resources, the methodology used to develop the Offer Review Trigger Price shall be the same as that used for new generation resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the programs' life.

(d) For new Real-Time Demand Response resources, the methodology used to develop the Offer Review Trigger Price is based on an analysis of the incremental operating costs associated with the demand response business activities of selected industry firms engaged primarily in the demand response business, as reported in their Form 10k filings with the U.S. Securities and Exchange Commission. The Internal Market Monitor will review data regarding annual customer totals (MW) and operating costs (cost of sales), allocated marketing and sales expense, and allocated administrative and general expense for the three preceding consecutive years. The incremental MW and the total incremental operating costs for each firm is calculated and the incremental cost is then divided by the incremental MW to estimate the incremental revenues required to cover the cost of new Real-Time Demand Response MW. The Offer Review Trigger Price is set to the lowest calculated incremental revenue value for the selected firms during the studied years rounded to the nearest whole number.

III.A.21.2 New Resource Offer Floor Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price, as described in this Section III.A.21.2.

(a) For a new capacity resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 or III.13.1.4.2.4, the New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price applicable to the relevant resource type.

(b) For a new capacity resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 and III.13.1.4.2.4, the Internal Market Monitor shall enter all relevant resource costs

and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate.

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a new Real-Time Demand Response resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred by the Demand Response Provider to acquire the Real-Time Demand Response resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the Real-Time Demand Response resource.

(iii) For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer price is consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price.

(vi) If the Internal Market Monitor determines that the requested offer price is not consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1.

III.A.21.3 Special Treatment of Certain Out-of-Market Capacity Resources in the Eighth Forward Capacity Auction.

For the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017), the provisions of Sections III.A.21.1 and III.A.21.2 shall also apply to certain resources that cleared in the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2015) and/or the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2016), as follows:

(a) This Section III.A.21.3 shall apply to: (i) any capacity clearing in the sixth or seventh Forward Capacity Auction as a New Generating Capacity Resource or New Import Capacity Resource designated as a Self-Supplied FCA Resource; and (ii) any capacity clearing in the sixth or seventh Forward Capacity Auction from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at prices found by the Internal Market Monitor to be not consistent with either: (a) the resource's long run average costs net of expected net revenues other than capacity revenues for a New Generating Capacity Resource and a New Demand Resource or (b) opportunity costs for a New Import Capacity Resource.

(b) For the eighth Forward Capacity Auction, the capacity described in subsection (a) above shall receive Offer Review Trigger Prices as described in Section III.A.21.1 and New Resource Offer Floor Prices as described in Section III.A.21.2. These values will apply to such capacity in the conduct of the eighth Forward Capacity Auction as described in Section III.13.2.3.2.

(c) For the eighth Forward Capacity Auction, the Project Sponsor or Lead Market Participant for such capacity may be required to comply with some or all of the qualification provisions applicable to new resources described in Section III.13.1. These requirements will be determined by the ISO on a case-by-case basis in consultation with the Project Sponsor or Lead Market Participant.

(d) For any capacity described in subsection (a) above that does not clear in the eighth Forward Capacity Auction:

(i) any prior election to have a Capacity Clearing Price and Capacity Supply Obligation continue to apply for more than one Capacity Commitment Period made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 shall be terminated as of the beginning of the Capacity Commitment Period associated with the eighth FCA (beginning June 1, 2017); and

(ii) after the eighth Forward Capacity Auction, such capacity will be deemed to have never been previously counted as capacity, such that it meets the definition, and must meet the requirements, of a new capacity resource for the subsequent Forward Capacity Auction in which it seeks to participate.

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

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

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

I.2.2. Definitions:

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

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

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

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

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

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

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

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

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

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

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

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

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

AGC is automatic generation control.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Asset Related Demand is a physical load that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of one or more

individual end-use metered customers receiving service from the same point or points of electrical supply, with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Bankruptcy Code is the United States Bankruptcy Code.

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

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

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

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

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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

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

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

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

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

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

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

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

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

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

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

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

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

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for the day); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy

(Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Commission is the Federal Energy Regulatory Commission.

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

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

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

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

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

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

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

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different

from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

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

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

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

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

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

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

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

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

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

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

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

Cost of New Entry (CONE) is the value that was determined by the ISO for each Forward Capacity Auction pursuant to the provisions of Section III.13 of Market Rule 1 in effect at the time of that auction.

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

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

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

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

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

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

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

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

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

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

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

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

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2017, Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts of a Demand Response Resource scheduled by the ISO as a result of the Day-Ahead Energy Market, multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1 and purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(ii) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(i) of Market Rule 1.

Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Program. The Day-Ahead Load Response Program allows Market Participants with registered Load Response Program Assets to make energy reduction offers into the Day-Ahead Load Response Program concurrent with the Day-Ahead Energy Market.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(iv) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(h) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(g) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.E1.6 and Section III.E2.6.

Demand Reduction Value is the quantity of reduced demand calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

Demand Resource is a resource defined as Demand Response Capacity Resources, On-Peak Demand Resources, Seasonal Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area pursuant to Appendix III.E1 and Appendix III.E2 of Market Rule 1, or during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

Demand Resource Commercial Operation Audit is an audit initiated pursuant to Section III.13.6.1.5.4.4.

Demand Resource Forecast Peak Hours are those hours, or portions thereof, in which, absent the dispatch of Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast.

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Operable Capacity Analysis means an analysis performed by the ISO estimating the expected dispatch hours of active Demand Resources given different assumed levels of Demand Resources clearing in the primary Forward Capacity Auction.

Demand Resource Performance Incentives means the additional monthly capacity payment that a Demand Resource may earn for producing a positive Monthly Capacity Variance in a period where other Demand Resources yield a negative monthly capacity variance.

Demand Resource Performance Penalties means the reduction in the monthly capacity payment to a Demand Resource for producing a negative Monthly Capacity Variance.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and the pumping load associated with pumped storage generators) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is the electricity consumption of an individual end-use customer at a Retail Delivery Point or the aggregated electricity consumption of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8A or Section III.8B.

Demand Response Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by

the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Demand Response Resource Notification Time is the minimum time, from the receipt of a Dispatch Instruction, that it takes a Demand Response Resource that was not previously reducing demand to start reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the time required from the time a Demand Response Resource that was not previously reducing demand starts reducing demand in response to a Dispatch Instruction and the time the resource achieves its Minimum Reduction.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for generation and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) is the Dispatch Rate expressed in megawatts.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Resources, change External Transactions, or change the status of a Dispatchable Asset Related Demand in accordance with the Resource's or contract's Supply Offer or Demand Bid parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output level of each generating Resource and each Dispatchable Asset Related Demand and each Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.13.1.4.6.1.

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions and must meet the technical requirements specified in the ISO New England Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources, however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation resources directly connected to end-use customer load and located behind the end-use customer's meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a wind resource must not exceed.

DR Auditing Period is the summer DR Auditing Period or winter DR Auditing Period as defined in Section III.13.6.1.5.4.3.1.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at prices of \$1.00/kW-month 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 (a) for Resources with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for Resources without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Resource and with meeting all environmental regulations and licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

EFT is electronic funds transfer.

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.5 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

Elective Transmission Upgrade Applicant is defined in Section II.47.5 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electronic Dispatch Capability is the ability to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of generating units and Dispatchable Asset Related Demands and the ability to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Resources.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum generation amount, in MWs, that a generating unit can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II of the Tariff.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while

delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange as determined by the ISO settlement process for the Energy Market.

Energy Offer Cap is \$1,000/MWh.

Energy Offer Floor is negative \$150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours and Energy Non-Zero Spot Market Settlement Hours.

Enrolling Participant is the Market Participant that registers Customers for the Load Response Program.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORD) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, the Capacity Requirement from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Estimated Net Regional Clearing Price (ENRCP) is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

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.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Generator means a generating unit that the ISO may dispatch within the hour through electronic dispatch and that meets the following criteria: (i) minimum run time does not exceed one hour; (ii) minimum down time does not exceed one hour; (iii) time to start does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Payment is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) of Market Rule 1.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Forecast Hourly Demand Reduction means the estimated maximum quantity of energy reduction (MWh), measured at the end-use customer meter that can be produced by a Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource, in each hour of an Operating Day. For a Real-Time Emergency Generation Asset that is metered at the generator and associated with a Real-Time Emergency Generation Resource, the Forecast Hourly Demand Reduction means the estimated maximum generator output (MWh) in each hour of an Operating Day.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual descending clock auction in the Forward Capacity Market, as described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is \$14,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a “Non-Market Participant FTR Customers” and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a generator that has been registered in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian

border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Adjusted Audited Demand Reduction is calculated in accordance with Section III.13.7.1.5.10.1.2.

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.2.7.1.1.1(a) of Market Rule 1.

Hourly Real-Time Demand Response Resource Deviation means the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.7.3.1.

Hourly Real-Time Emergency Generation Resource Deviation is calculated pursuant to Section III.13.7.1.5.8.3.1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadequate Supply is defined in Section III.13.2.8.1 of Market Rule 1.

Inadvertent Energy Revenue is defined in Section III.3.2.1(k) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(l) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled generation at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Insufficient Competition is defined in Section III.13.2.8.2 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Agreement is the “Large Generator Interconnection Agreement” or the “Small Generator Interconnection Agreement” pursuant to Schedules 22 and 23 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 of the OATT.

Interconnection Procedure is the “Large Generator Interconnection Procedures” or the “Small Generator Interconnection Procedures” pursuant to Schedules 22 and 23 of the ISO OATT.

Interconnection Request has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Intermittent Power Resource is defined in Section III.13.1.2.2.2 of Market Rule 1.

Intermittent Settlement Only Resource is a Settlement Only Resource that is also an Intermittent Power Resource.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load

Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers or Demand Bids for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead

Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means generating resources that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, or Real-Time Demand Response Event Hours to other hours and reduce the amount of capacity needed, while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, chilled water storage, and other forms of electricity storage.

Load Response Program means the program implemented and administered by the ISO to promote demand side response as described in Appendix E to Market Rule 1.

Load Response Program Asset means one or more individual end-use metered customers that report load reduction and consumption, or generator output as a single set of values, are assigned an identification number, that participate in the Load Response Program and which encompass assets registered in the Real-Time Price Response Program or Real-Time Demand Response Assets, and are further described in Appendix E of Market Rule 1.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA.

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone or Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location also is a Dispatch Zone.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone or

Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

Long Lead Time Generating Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart CIP Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Major Transmission Outage is a major transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b)(v) of Market Rule 1.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm

load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1, to meet the Installed Capacity Requirement.

Maximum Consumption Limit is the maximum amount, in MW, available from the Dispatchable Asset Related Demand for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data except that a Self-Scheduled Dispatchable Asset Related Demand may modify its Minimum Consumption Limit on an hourly basis, as part of its Demand Bid, in order to indicate the desired level of Self-Scheduled MW.

Maximum Facility Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand of a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset, where the demand evaluated is established by adding actual metered demand and the output of all generators located behind the asset's end-use customer meter in the same time intervals.

Maximum Generation is the maximum generation output of a Real-Time Demand Response Asset comprised of Distributed Generation or the maximum generation output of a Demand Response Asset comprised of Distributed Generation.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset's peak load less its uninterruptible load. For assets that deliver reductions through the use of generation, the Maximum Interruptible Capacity is the difference between the generator's maximum possible output and its expected output when not providing demand reduction.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, of a Demand Response Asset, Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time a Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the Demand Reduction Value of the Demand Resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the Demand Reduction Value for an Existing Demand Resource is not overstated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1, which includes Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by a Demand Resource supplier as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by Demand Resource suppliers during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Minimum Consumption Limit is the minimum amount, in MW, available from a Dispatchable Asset Related Demand that is not available for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data.

Minimum Down Time is the number of hours that must elapse after a Generator Asset has been released for shutdown at or below its Economic Minimum Limit before the Generator Asset can be brought online and be released for dispatch at its Economic Minimum Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources to operate at or below Economic Minimum Limit, in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency 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 Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Time Between Reductions is the minimum number of hours that a Market Participant requires between the time the Demand Response Resource receives a Dispatch Instruction from the ISO to not reduce demand and the time the Demand Response Resource receives a Dispatch Instruction from the ISO to reduce demand.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Variance means a Demand Resource's actual monthly Capacity Value established pursuant to Section III.13.7.1.5.1 of Market Rule 1, minus the Demand Resource's final Capacity Supply Obligation for the month.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

NCPC Credit means the payment made to a Resource as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NERC is the North American Electric Reliability Corporation or its successor organization.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net 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.13.2.8.1.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.2 of Market Rule 1.

New Demand Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III 13.1.4.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Resource.

New Demand Resource Show of Interest Form is described in Section III.13.1.4.2 of Market Rule 1.

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but does not have a winter audit value and a summer audit value.

New Demand Response Asset Audit is an audit of a New Demand Response Asset performed pursuant to Section III.13.6.1.5.4.8.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Nodal Amount is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a generating unit that must be paid to Market Participants with an Ownership Share in the unit for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the generating unit is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.3.1.3.

Non-Commercial Capacity, 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-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Intermittent Settlement Only Resource is a Settlement Only Resource that is not an Intermittent Power Resource.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-Price Retirement Request is a binding request to retire the entire capacity of a Generating Capacity Resource as described in Section III.13.1.2.3.1.5.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2017. Demand Response Resources for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value between 0 and the CLAIM10 of a Resource that represents the amount of TMNSR available from the Resource.

Offered CLAIM30 is a Supply Offer value between 0 and the CLAIM30 of a Resource that represents the amount of offline TMOR available from the Resource.

Offered Full Reduction Time is the Demand Response Resource Notification Time plus the Demand Response Resource Start Up Time plus $((\text{the Maximum Reduction} - \text{the Minimum Reduction})$ divided by the Demand Response Resource Ramp Rate).

On-Peak Demand Resource is a type of Demand Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service

Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a generating unit asset or Load Asset, where such unit or load is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The “Phase I Transfer Capability” is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical

software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credit is calculated pursuant to Section III.F.2.6.2 of Appendix F to Market Rule 1.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource or New Demand Resource participate in the Forward Capacity Market, as described in Section III.13.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b)(iii) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(c)(iii) of Market Rule 1.

Real-Time Commitment Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

Real-Time Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E1.8 for Capacity Commitment Periods commencing prior to June 1, 2017, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2017.

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Real-Time Demand Response Resources of such hours.

Real-Time Demand Response Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Demand Response Resource.

Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing

electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

Real-Time Emergency Generation Resource is Distributed Generation whose federal, state and/or local air quality permits, rules or regulations limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(ii) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(c)(ii) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b)(i) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(c)(i) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b)(iv) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(c)(iv) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Price Response Program is the program described in Appendix E to Market Rule 1.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the

other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capability (REGCAP) means the amount of Regulation capability available on a Market Participant's Resource as calculated by the ISO based upon that Resource's Automatic Response Rate and the available regulating range as specified in ISO New England Manual 11 – Market Operations.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.

Regulation Rank Price is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

Regulation Requirement is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

Regulation Service Credit is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

Regulation Service Megawatts are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, for Capacity Commitment Periods commencing on or after June 1, 2017, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in \$/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2017, a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission’s corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

Seasonal Peak Demand Resource is a type of Demand Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Self-Schedule is the action of a Market Participant in committing or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing or scheduling a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been scheduled or dispatched by the ISO to provide the Energy. For a Dispatchable Asset Related Demand, Self-Schedule is the action of a Market Participant in committing or scheduling a Dispatchable Asset Related Demand to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the Dispatchable Asset Related Demand would have been scheduled or dispatched by the ISO to consume Energy. Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to: (i) a Generator Asset's Economic Minimum Limit; (ii) a Dispatchable Asset Related Demand's Minimum Consumption Limit; or (iii) for Regulation purposes with respect to 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.

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.1(c) of Market Rule 1.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. The daily bid Blocks in the price-based Real-Time offer/bid will be multiplied by the number of hours in the day to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, or Schedule 23 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock; (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) means the reserve capability of a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control

Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Time-on-Regulation Credit is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

Time-on-Regulation Megawatts is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart O&M Payment is the annual compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency

Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or

a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than \$0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Supplemental Availability Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: “Pre-scheduling” as specified in Section III.1.9, “Scheduling” as specified in III.1.10, and “Dispatch” as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 **[Reserved.]**

III.1.3.2 **[Reserved.]**

III.1.3.3 **[Reserved.]**

III.1.4 **Requirements for Certain Transactions.**

III.1.4.1 **ISO Settlement of Certain Transactions.**

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 **Transactions Subject to Requirements of Section III.1.4.**

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Supplemental Availability Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as “Section III.1.4 Transactions,” and individually as a “Section III.1.4 Transaction.” Transactions that conform to the standards are referred to collectively as “Section III.1.4 Conforming Transactions,” and individually as a “Section III.1.4 Conforming Transaction.”

III.1.4.3 **Requirements for Section III.1.4 Conforming Transactions.**

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a “Related Transaction”), where the Related Transaction:

- (i) is not cleared or settled by the ISO as Counterparty;
- (ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

- (iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and
 - (iv) is not contingent on either party to carry out the Section III.1.4 Transaction.
- (b) In addition, to qualify as a Section III.1.4 Conforming Transaction:
- (i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;
 - (ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and
 - (iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.
- (c) As further requirements:
- (i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and
 - (ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

- (a) Three types of Claimed Capability Audits may be performed:
 - (i) An Establish Claimed Capability Audit establishes the Generator Asset's ability to respond to ISO dispatch instructions and to maintain performance at a specified output level for a specified duration.

- (ii) A Seasonal Claimed Capability Audit determines a Generator Asset's capability to perform under specified summer and winter conditions for a specified duration.
- (iii) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value.
- (b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.
- (c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.
- (d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.
- (e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

- (a) The time and date of an Establish Claimed Capability Audit shall be unannounced.
- (b) For a newly commercial Generator Asset:
 - (i) An Establish Claimed Capability Audit will be scheduled by the ISO within seven Business Days of the commercial operation date for all Generator Assets except:
 1. Non-intermittent daily cycle or run of river hydro; and
 2. Intermittent, net-metered, or special qualifying facilities.
 - (ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
 - (iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.
- (c) For Generator Assets with an Establish Claimed Capability Audit value:
 - (i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.
 - (ii) An Establish Claimed Capability Audit shall be performed within seven Business Days of the date of the request.

- (iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
- (iv) The Establish Claimed Capability Audit values become effective seven Business Days following notification of the audit results to the Market Participant by the ISO.
- (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (d) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.
- (e) Establish Claimed Capability Audits shall be performed on Business Days between 0800 and 2200.
- (f) To conduct an Establish Claimed Capability Audit, the ISO shall:
 - (i) Notify the Designated Entity immediately prior to issuing the Dispatch Instruction that an audit will be conducted.
 - (ii) Ensure that the Generator Asset is Self-Scheduled for the time to ramp to its full capability and for the duration of the Establish Claimed Capability Audit.
 - (iii) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the asset's net output to increase from the current operating level to its Real-Time High Operating Limit.
 - (iv) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.
- (g) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit		
Unit Type	Summer Claimed Capability Audit Duration (Hrs)	Winter Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	4	4
Combined Cycle Total Unit, Integrated Coal Gasification Combustion Cycle, Pressurized Fluidized Bed Combustion	4	4
Combustion Gas Turbine	1	1

Internal Combustion Engine	1	1
Hydraulic Turbine – Reversible	4	2
Hydro-Conventional Weekly	2	2

III.1.5.1.3. Seasonal Claimed Capability Audits.

- (a) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:
 - (i) Intermittent, net-metered, and special qualifying facilities; and
 - (ii) Non-intermittent daily cycle and run of river hydro.
- (b) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset’s Seasonal Claimed Capability Audit obligation.
- (c) Except as provided in Section III.1.5.1.3(m) below, a summer Seasonal Claimed Capability Audit must be conducted:
 - (i) At least once every Capability Demonstration Year;
 - (ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.
- (d) A winter Seasonal Claimed Capability Audit must be conducted:
 - (i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:
 - (1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.
 - (2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.
 - (ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.
- (e) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:
 - (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the seventh Business Day following the day on which the audit concludes.

- (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.
- (f) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
- (g) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(c) and (d), the Seasonal Claimed Capability Audit value for the season shall be set to zero.
- (h) The Seasonal Claimed Capability Audit value shall become effective seven Business Days following notification of the audit results to the Market Participant by the ISO.
- (i) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit		
Unit Type	Summer Claimed Capability Audit Duration (Hrs)	Winter Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	2	2
Combined Cycle Total Unit, Integrated Coal Gasification Combustion Cycle, Pressurized Fluidized Bed Combustion	2	2
Combustion Gas Turbine	1	1
Internal Combustion Engine	1	1
Hydraulic Turbine-Reversible	2	2
Hydro-Conventional Weekly	2	2

- (j) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:
 - (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;
 - (ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

- (iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.
- (k) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) any time the temperature requirements were met at the Generator Asset's location the ISO denied the audit request, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:
 - (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;
 - (ii) Retain the current Seasonal Claimed Capability Audit value for the season; and
 - (iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.
- (l) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.
- (m) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:
 - (i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(e).

- (ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.
- (iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.
- (iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(c)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.
- (v) This Section III.1.5.1.3(m) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

III.1.5.1.4. ISO-Initiated Claimed Capacity Audits.

- (a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.
- (b) An ISO-Initiated Claimed Capability Audit value shall replace the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:
 - (i) The Establish Claimed Capability Audit values may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.
 - (ii) An ISO-Initiated Claimed Capability Audit value shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.
- (c) If a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.
- (d) Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective seven Business Days following notification of the audit results to the Market Participant by the ISO.
- (e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:
 - (i) Notify the Designated Entity, immediately prior to issuing the Dispatch Instruction, that an audit will be conducted.

- (ii) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.
 - (iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.
- (f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit		
Unit Type	Summer Claimed Capability Audit Duration (Hrs)	Winter Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	4	4
Combined Cycle Total Unit, Integrated Coal Gasification Combustion Cycle, Pressurized Fluidized Bed Combustion	4	4
Combustion Gas Turbine	1	1
Internal Combustion Engine	1	1
Hydraulic Turbine – Reversible	4	2
Hydro-Conventional Daily Pondage, Hydro-Conventional Run of River	2	2
Hydro-Conventional Weekly	2	2
Wind	2	2
Photovoltaic	2	2
Fuel Cell	2	2

III.1.5.2 ISO-Initiated Parameter Auditing.

- (a) The ISO may perform an audit of any Supply Offer parameter that impacts the ability of a Generator Asset to provide real-time energy or reserves.
- (b) Audits shall be performed using the following methods:

- (i) **Economic Maximum Limit.** The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.
 - (ii) **Manual Response Rate.** The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.
 - (iii) **Start-Up Time.** The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.
 - (iv) **Notification Time.** The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.
 - (v) **CLAIM10.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5 of Market Rule 1.
 - (vi) **CLAIM30.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5 of Market Rule 1.
 - (vii) **Automatic Response Rate.** The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second ISO-issued electronic Dispatch Instructions.
- (c) To Conduct an audit based upon historical data, the ISO shall:
 - (i) Obtain data through random sampling of generator performance in response to ISO Dispatch Instructions; or
 - (ii) Obtain data through continual monitoring of generator performance in response to ISO Dispatch Instructions.
 - (d) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset for the parameters being audited.
 - (e) To the extent that the audit results indicate a Market Participant is providing Supply Offer parameter values that are not representative of the actual capability of the Generator Asset, Supply Offer parameter values for the Generator Asset shall be restricted to the value that is supported by the audit.
 - (f) In the event that a Generator Asset has had a Supply Offer parameter value restricted:
 - (i) The Lead Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:
 1. Provide an explanation of the discrepancy;

2. Indicate the steps that the Market Participant will take to re-establish the Supply Offer parameter's value;
3. Indicate the timeline for completing the restoration; and
4. Explain the testing that the Market Participant will undertake to verify restoration of the Supply Offer parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the Supply Offer parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the Supply Offer parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 **ISO New England Manuals and ISO New England Administrative Procedures.**

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 **General.**

III.1.7.1 **Provision of Market Data to the Commission.**

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 **[Reserved.]**

III.1.7.3 **Agents.**

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 **[Reserved.]**

III.1.7.5 **[Reserved.]**

III.1.7.6 **Scheduling and Dispatching.**

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch.

(b) In the event that one or more Resources cannot be scheduled in the Day-Ahead Energy Market on the basis of a least-cost, security-constrained dispatch as a result of one or more Self-Schedule offers contributing to a transmission limit violation, the following scheduling protocols will apply:

(i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.

(ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers

will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.

(iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy bought and sold by the ISO in the New England Markets will reflect the hourly Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices in an hour caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices in an hour, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect the integrated hourly Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.10 Other Transactions.

(a) Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the obligations of Market Participants to make resources with a Capacity Supply Obligation available for dispatch by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

(b) [Reserved.]

(c) [Reserved.]

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

- (a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.
- (b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.
- (c) The Seasonal Claimed Capability of a Generator Asset is:
- (i) Based upon hydrology data for non-intermittent daily cycle and run of river hydro as described in Section III.13.1.2.2.2.
 - (ii) The median real power output during reliability hours for intermittent, net metered and special qualifying facilities, as reflected in hourly revenue metering data as described in Section III.13.1.2.2.2.
 - (iii) For all other Generator Assets, the minimum of: i) the Generator Asset's current Establish Claimed Capability Audit value and ii) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

III.1.7.12 [Reserved.]

III.1.7.13 **[Reserved.]**

III.1.7.14 **[Reserved.]**

III.1.7.15 **[Reserved.]**

III.1.7.16 **[Reserved.]**

III.1.7.17 **Operating Reserve.**

The ISO shall schedule to the Operating Reserve and load-following requirements of the New England Control Area and the New England Markets in scheduling Resources pursuant to this Market Rule 1. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 **Regulation.**

(a) Regulation shall be supplied from generators located within the metered electrical boundaries of the New England Control Area. Market Participants offering Regulation shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall obtain and maintain an amount of Regulation equal to the New England Control Area Regulation objective as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) The Regulation range of a unit shall be at least twice the amount of Regulation assigned and no less than the minimum specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(d) A unit that is providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided. The amount of Regulation provided by a unit shall serve to redefine the Economic Minimum Limit and Economic Maximum Limit of that unit, in that the amount of Regulation shall be added to the unit's Economic Minimum Limit or automatic low limit while regulating, whichever is greater, and subtracted from its Economic Maximum Limit or automatic high limit, whichever is less. Qualified Regulation must satisfy the verification tests described in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19 Ramping.

A generating unit dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the unit's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the ISO for that unit and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19A Real-Time Reserve.

(a) Real-Time TMSR, TMNSR, TMOR and Real-Time Replacement Reserve, if applicable, shall be supplied from Resources located within the metered boundaries of the New England Control Area subject to the condition set forth in Section III.1.7.19A(c) below. The ISO shall designate Operating Reserve in Real-Time only to Market Participant Resources that comply with the applicable standards and requirements for provision and dispatch of Operating Reserve capability as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and locational Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) External Resources will be permitted to participate in the Real-Time reserve market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO units that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output levels of generating units, or change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment is operated with control equipment functioning as specified in the ISO New England Manuals & ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market, along with Dispatch Rate levels above which it does not desire to purchase.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning generating Resources and Dispatchable Asset Related Demand Resources required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output for the pertinent Operating Day.

III.1.8 [Reserved.]

III.1.9 **Pre-scheduling.**

III.1.9.1 [Reserved.]

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 **Market Participant Responsibilities.**

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each generating unit as to which

the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 **[Reserved.]**

III.1.10 **Scheduling.**

III.1.10.1 **General.**

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of generating Resources with notification time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers for such units, as submitted in accordance with Section 1.10.1A(f), for such periods and the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and such Resources shall be treated as Pool-Scheduled Resources and shall be eligible to receive NCPC Credits under Section III.3.2.3 in accordance with the binding Supply Offers submitted.

III.1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 10:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resource increments, including hydropower units, Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market

Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the energy Supply Offer limitation specified in this Section.

(b) [Reserved.]

(c) All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) If the sum of all submitted fixed External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all fixed External Transaction sales at the applicable External Node shall be set equal to the Energy Offer Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, notification times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(d) Market Participants selling into the New England Markets, from either internal Resources or External Resources, shall submit Supply Offers or External Transactions for the supply of energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Regulation, Operating Reserve or other services as applicable, for the following Operating Day.

Energy offered from generating Resources without a Capacity Supply Obligation shall not be supplied from Resources that are included in or otherwise committed to supply the operating reserve requirements of another Control Area. All Supply Offers and Demand Bids:

(i) Shall specify the Resource or Load Asset and energy for each hour of the Operating Day;

(ii) Shall specify, for Supply Offers, Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The price and quantity values in a Block may each vary on an hourly basis;

(iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify, for Supply Offers, Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee values may vary on an hourly basis;

(iv) For a dual fuel Resource, shall specify, for Supply Offers, the fuel type. The fuel type value may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual fuel Resources in Section III.A.3 of Appendix A;

- (v) Shall specify, for Supply Offers, a Minimum Run Time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;
- (vi) Supply Offers shall constitute an offer to submit the generating Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect maximum energy available for the Operating Day, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;
- (vii) Shall constitute, for Demand Bids, an offer to submit the Dispatchable Asset Related Demand Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes to the Maximum Consumption Limit and Minimum Consumption Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Minimum Consumption Limit may vary on an hourly basis to reflect the Self-Scheduled consumption level of the Resource;
- (viii) Shall be final as to the price or prices at which the Market Participant proposes to supply or consume energy or other services to the New England Markets, such price or prices for Resources or portions of Resources scheduled in the Day-Ahead Energy Market being guaranteed by the Market Participant for the period extending through the end of the following Operating Day or, in the case of a generating Pool-Scheduled Resource continuing to run into the second Operating Day to satisfy its Minimum Run Time, such price or prices being guaranteed by the Market Participant for the period extending into the second Operating Day that satisfies the Resource's Minimum Run Time; and
- (ix) Shall not specify an energy offer or bid price below the Energy Offer Floor or above the Energy Offer Cap.

(e) A Market Participant that wishes to make a Resource available to sell Regulation service shall submit a Supply Offer for Regulation, the price and quantity of which can vary on an hourly basis. The Supply Offer for Regulation shall specify the Automatic Response Rate in megawatts per minute, the price in dollars per MWh of the Regulation capability being offered, such Regulation capability as calculated by the ISO by multiplying the submitted Automatic Response Rate by five minutes, and such other information specified by the ISO as may be necessary to evaluate the Supply Offer and the generating Resource's Regulation Opportunity Costs. The price of the Supply Offer shall not exceed \$100/MWh. Qualified Regulation capability must satisfy the verification tests specified in the ISO New England Manuals and ISO New England Administrative Procedures. Regulation capability amounts will be adjusted as necessary in the case where a generating unit's compliance rating is less than 90%. The audited Regulation capability will be deemed equal to the most recently calculated compliance rating times the 5-minute Regulation capability quantities utilized in that compliance rating calculation, rounded to the nearest whole megawatt. The Resource's Automatic Response Rate will then be adjusted based upon the audited Regulation capability.

(f) Each Market Participant owning or controlling the output of a resource with a Capacity Supply Obligation shall submit a forecast of the availability of each such resource for the next seven days. A Market Participant may submit a non-binding forecast of the price at which it expects to offer a generating Resource increment to the ISO over the next seven days.

(g) Each Supply Offer or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Resource and an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The

Economic Maximum Limits and Economic Minimum Limits are not used in determining the amount of energy (MW) in each marginal Supply Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits and Economic Minimum Limits.

(j) In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers to sell energy in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as generators committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide energy in the Real-Time dispatch unless the schedules for such units are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy and related services, Start-Up Fees, No-Load Fees, and the specified operating characteristics, offered by Market Participants to the ISO by the offer deadline specified in Section III.1.10.1A.

(b) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

(c) Market Participants offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) The Market Participant seller whose Resource is selected as a Pool-Scheduled Resource shall receive payments or credits for energy or related services, or for Start-Up Fees and No-Load Fee, from the ISO on behalf of the Market Participant buyers in accordance with Section III.3 of this Market Rule 1. Additionally, the Market Participant seller shall receive for Pool-Scheduled Resources scheduled in the Real-Time Energy Market that were not scheduled in the Day-Ahead Energy Market, a pro-rata share of its applicable Start-Up Fee if the ISO cancels its selection of the Resource as a Pool-Scheduled Resource and so notifies the Market Participant seller before the Resource is synchronized (“Cancellation Fee”).

(e) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

(f) Eligibility for NCPC in the Day-Ahead Energy Market under Section III.3.2.3 is affected by Resource Self-Schedules. The specific rules related to the impact of Resource Self-Schedules on eligibility for NCPC may be found in *Appendix F* of this Market Rule 1.

(g) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 is affected by Resource Self-Schedules. The specific rules related to the impact of Resource Self-Schedules on eligibility for NCPC may be found in *Appendix F* of this Market Rule 1.

(h) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 may be affected by Resource trips. The specific rules related to the impact of Resource trips on eligibility for NCPC may be found in *Appendix F* of this Market Rule 1.

(i) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 is affected by ramping up in response to a start-up instruction and ramping down in response to a shutdown instruction. The specific rules related to the ramping impacts on eligibility for NCPC may be found in *Appendix F* of this Market Rule 1.

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures.

- (a) The minimum duration of a Self-Schedule for a Generator Asset shall not result in the Generator Asset operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer.
- (b) The offered prices of Resources or portions of Resources that are Self-Scheduled, or otherwise not following the dispatch orders of the ISO, shall not be considered by the ISO in determining Locational Marginal Prices.
- (c) A Market Participant with a Resource that does not have a Capacity Supply Obligation shall comply with the requirements in Section III.13.6.2 when Self-Scheduling that Resource.
- (d) A Market Participant Self-Scheduling a Resource in the Day-Ahead Energy Market that does not deliver the energy in the Real-Time Energy Market, shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.4 [Reserved.]

III.1.10.5 External Resources.

- (a) Market Participants with External Resources that have dynamic scheduling and dispatch capability may submit Supply Offers to the New England Markets in accordance with the Day-Ahead and Real-Time scheduling processes specified above. Market Participants must submit Supply Offers for External Resources on a Resource specific basis. An External Resource with dynamic scheduling and dispatch capability selected as a Pool-Scheduled Resource shall be made available for scheduling and dispatch at the direction of the ISO and shall be compensated on the same basis as other Pool-Scheduled Resources.
- (b) Supply Offers for External Resources with dynamic scheduling and dispatch capability shall specify the Resource being offered, along with the information specified in the Offer Data as applicable.

(c) For Resources external to the New England Control Area that are not capable of dynamic scheduling and dispatch, Market Participants shall submit External Transactions as detailed in Section III.1.10.7 of this Market Rule 1.

(d) A Market Participant whose External Resource is capable of dynamic scheduling and dispatch capability or whose External Transaction does not deliver the energy scheduled in the Day-Ahead Energy Market shall replace such energy not delivered as scheduled in the Day-Ahead Energy Market with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.6 Dispatchable Asset Related Demand Resources.

External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demand Resources. Except as noted below with respect to a pumped storage generator that does not have a Capacity Supply Obligation, a Dispatchable Asset Related Demand Resource in the New England Control Area must:

(a) each day, either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy, unless and to the extent that the Dispatchable Asset Related Demand Resource is unable to do so due to an outage as defined in the ISO New England Manuals;

(b) submit Demand Bid data that specifies a Maximum Consumption Limit and Minimum Consumption Limit;

(c) submit Demand Bid data that specifies a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit;

(d) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand Resource's ability to interrupt and the expected return date from the outage;

(e) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;

(f) abide by the ISO maintenance coordination procedures;

(g) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand Resource; and

(h) comply with the ISO New England Manuals.

To schedule the dispatchable pumping demand of a pumped storage generator that does not have a Capacity Supply Obligation, a Market Participant must comply with the requirements in (b) through (h) for the applicable Operating Day and must either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy for the applicable Operating Day.

III.1.10.7 External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the applicable procedures governing the Emergency, as set forth in ISO New England Manual 11, require a change in schedule.

(d) A Market Participant submitting a priced External Transaction supporting Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must comply with the requirements in Section III.13.6.1.2.1 with respect to linking the transaction to the associated transmission reservation and NERC E-Tag. All other External Transactions submitted to the Real-Time Energy Market must contain the associated NERC E-Tag and

transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) All Real-Time External Transactions shall be scheduled and curtailed in accordance with the ISO New England Manuals and all applicable tariffs.

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in

accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

- (3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;
- (4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.
- (iv) Unconstrained Export Transactions:
 - (1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;
 - (2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;
 - (3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;
 - (4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;
 - (5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.
- (g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.
 - (i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy

Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) Day-Ahead NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.5.

(ii) Real-Time NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.16.

(iii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iv) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.8 ISO Responsibilities.

(a) The ISO shall use its best efforts to determine (i) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market. In making these determinations, the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve

and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Pool-Scheduled Resources and to direct that schedules be changed in an Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to generation Supply Offers and revisions to Demand Bids for any Dispatchable Asset Related Demand Resource. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and

shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

(i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual fuel Resources), the quantity and price pairs of its Blocks, and the Supply Offer for Regulation may be modified.

(ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(c) During the Re-Offer Period, Market Participants may submit revisions to priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may at any time, consistent with the provisions in Manual 11, request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect.

(d) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit.

(e) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(b), then:

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched as though it had offered for the hour in question at a Self-Scheduled MW.

(f) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output.

The ISO shall have the authority to direct any Market Participant to adjust the output of any Pool-Scheduled Resource increment within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources, subject to an obligation to pay any applicable Start-Up Fees, No-Load Fee, or Cancellation Fees. The ISO shall adjust the output of Pool-Scheduled Resource increments as necessary:

(a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (c) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Pool-dispatched Resources.

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Pool-Scheduled Resource increments and the designation of Real-Time Operating Reserve to Pool-Scheduled Resource increments, including the dispatchable increments from resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall ensure that the entity controlling a Pool-Scheduled Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified. During each hour of any tests performed under Section III.1.11.3(c),(i), the Resources under test shall be considered Self-Scheduled Resources for the purposes of calculating NCPC Credits. Procedures related to the ISO's modification of operational related Offer Data and Market Participant requests for testing shall be as defined in the ISO New England Manuals.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to dispatched output levels as practical, consistent with Good Utility Practice.

(e) Wind resources are treated as not economically dispatchable until the ISO is technically capable of determining and telemetering a Do Not Exceed Dispatch Point to the resource.

(f) The ISO may request that dual-fueled generating Resources that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fueled units that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fueled units that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 Regulation.

(a) A Market Participant may satisfy its Regulation obligation from its own Resources capable of performing Regulation service or by purchases from the ISO through the New England Markets at the rates set forth in Section III.3.2.2.

(b) The ISO shall obtain Regulation service from the least-cost alternatives available from either Pool-Scheduled Resources or Self-Scheduled Resources as needed to meet New England Control Area requirements not otherwise satisfied by the Market Participants. The ISO assigns Regulation to eligible generating units using the ISO Regulation assessment software. The Regulation assessment software calculates, at five minutes after the hour and on demand as needed, the optimal set of generating units required to meet the Regulation Requirement. The software first calculates a Regulation Rank Price,

based on estimates of Time-on-Regulation Credits, Regulation Service Credits, estimated Regulation Opportunity Costs, Regulation Capability and other factors, as specified below, that consider the impact of Regulation assignment on the Real-Time Energy Market. An interim clearing price is then calculated and the Regulation Rank Prices are updated using this interim clearing price to recognize that actual payments for Regulation are based upon the Regulation Clearing Price and not the Regulation offer price. The software continues to iterate in this manner until convergence is reached, resulting in an optimal selection of generating units for Regulation assignment. The ISO utilizes the output from this software when evaluating the set of generating units for Regulation assignment. In the event that one or more generating units to be selected have equal Regulation Rank Prices, the ISO shall select the generating unit for Regulation assignment with the largest Regulation Capability. Details of the process and calculations are described below.

- (1) At the start of each operating hour, the ISO calculates an initial Regulation Rank Price for each eligible unit offering to provide Regulation using the ISO's Regulation assignment software. The initial Regulation Rank Price for each unit is equal to the sum of the following calculations divided by that unit's Regulation Capability:
 - (a) Time-on-Regulation Credit estimate calculated as the product of the Regulation Capability times the Regulation offer price;
 - (b) Regulation Service Credit estimate is set equal to the Time-on-Regulation Credit estimate to meet the 50/50 revenue mix objective as determined by the ISO in accordance with procedures specified in the ISO New England Manuals and ISO New England Administrative Procedures;
 - (c) Regulation Opportunity Cost estimate calculated as the product of the opportunity cost MW times the opportunity cost price differential where:
 - (i) Opportunity cost MW is calculated as the absolute value of the difference between the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by Economic Max and Economic Min, and EstRegGen.
 - (ii) EstRegGen is the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by RSETHI and RSETLO. RSETHI is equal to the Regulation

High Limit – Regulation Capability. RSETLO is equal to the Regulation Low Limit + Regulation Capability.

(iii) To more accurately estimate the actual Regulation Opportunity Cost, EstRegGen is further constrained as follows to account for units with large regulating ranges and slow response rates: if actual generation is less than EstRegGen and EstRegGen is greater than RSETLO, then EstRegGen is constrained up by the greater of (actual output + (SlowWideTime * Automatic Response Rate)) and RSETLO; if actual generation is greater than EstRegGen and EstRegGen is less than RSETHI, then EstRegGen is constrained down by the lesser of (actual output – (SlowWideTime * Automatic Response Rate)) and RSETHI. The SlowWideTime is determined by the ISO based upon empirical studies. The initial SlowWideTime value, and subsequent updates, shall be posted on the ISO's website.

(iv) Opportunity cost price differential is calculated as the absolute value of the difference between the average offer price of the opportunity MW and the Real-Time nodal LMP of the unit.

(d) Lookahead penalty estimate. The lookahead calculation assigns a cost penalty to units in the selection process if there is a change in energy offer prices near EstRegGen. It is calculated as 0.17 multiplied by the greater of:

(i) the unit's energy offer price at a higher output level (LookupRegGen as defined below) minus its energy offer price at EstRegGen, multiplied by (LookupRegGen – EstRegGen);
and

(ii) the unit's energy offer price at EstRegGen minus its energy offer price at a lower output level (LookdownRegGen as defined below), multiplied by (EstRegGen -LookdownRegGen),
where,

LookupRegGen = (EstRegGen + (LookAheadMinutesUp * Automatic Response Rate)) as bounded by Regulation High Limit; and LookdownRegGen = (EstRegGen – (LookAheadMinutesDown * Automatic Response Rate) as bounded by Regulation Low Limit),
And where the initial values of LookAheadMinutesUp and LookAheadMinutesDown, and subsequent updates, will be posted on the ISO's website.

(e) A tiebreaker adder is calculated for both pool-scheduled and Self-Scheduled Regulation units. The tiebreaker adder is equal to a tiebreaker multiplier (.000001) times the difference between a tiebreaker megawatt reference value (500 MW) and the Regulation Capability of the unit.

For Self-Scheduled Regulation, all values calculated under this Section III.1.11.5(b)(1) are set equal to zero except for the tiebreaker adder.

(2) The ISO's Regulation assignment software creates an initial merit order stack of eligible Regulation Capability by sorting the generating units by the initial Regulation Rank Prices calculated under Section III.1.11.5 (b)(1) in ascending order. Generating units are then selected in rank order until the Regulation Requirement is met. An initial clearing price is then calculated based upon the highest Regulation offer price associated with the initial set of generating units selected to meet the Regulation Requirement. Updated Regulation Rank Prices are then recalculated for generating units with Regulation offer prices that are less than the initial clearing price by substituting the initial clearing price for the generating unit's Regulation offer price, recalculating the Time-On-Regulation Credit and the Regulation Service Credit estimates; adding the originally calculated values under Sections III.1.11.5(b)(1)(c), (d) and (e) to these recalculated values and dividing this total by the unit's Regulation Capability. These updated Regulation Rank Prices are utilized along with the initial Regulation offer prices adjusted to include opportunity costs that are greater than or equal to the initial clearing price to create an updated generating unit list sorted by ascending Regulation Rank Prices. An updated clearing price is then calculated and the software continues to iterate in this manner until convergence is reached producing an optimal generating unit rank order list for use in assigning Regulation.

(3) Shortly after the start of an hour and during the hour as needed, the ISO updates the generating unit rank order list using the ISO's Regulation assignment software based on any changes to Regulation Capability eligibility and other current information, including any changes to Self-Schedule Regulation. The ISO uses this updated Regulation rank order list to assign Regulation for the upcoming hour and to make changes to Regulation assignments within the hour.

(c) The ISO shall dispatch Resources for Regulation by sending Regulation signals and instructions to Resources from which Market Participants, in accordance with the ISO New England Manuals and ISO

New England Administrative Procedures, have offered Regulation service. Market Participants shall comply with Regulation dispatch signals and instructions transmitted by the ISO and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources supplying load in the New England Control Area as close to desired output levels as practical, consistent with Good Utility Practice.

III.1.11.6 **[Reserved]**

III.1.12 **Dynamic Scheduling.**

Dynamic scheduling can be requested and may be implemented in accordance with the following procedures:

- (a) An entity that owns or controls a generating Resource in the New England Control Area may electrically remove all or part of the generating Resource's output from the New England Control Area through dynamic scheduling of the output to load outside the New England Control Area. Such output shall not be available for economic dispatch by the ISO.

- (b) An entity that owns or controls a generating Resource outside of the New England Control Area may electrically include all or part of the generating Resource's output into the New England Control Area through dynamic scheduling of the output to load inside the New England Control Area. Such output shall be available for economic dispatch by the ISO.

- (c) An entity requesting dynamic scheduling shall be responsible for arranging for the provision of signal processing and communication from the generating unit and other participating Control Area and complying with any other procedures established by the ISO regarding dynamic scheduling as set forth in the ISO New England Manuals. Allocation of costs associated with dynamic scheduling shall be determined and filed with the Commission following the first request.

- (d) An entity requesting dynamic scheduling shall be responsible for reserving amounts of appropriate transmission service necessary to deliver the range of the dynamic transfer and any ancillary services.

III.2 LMPs and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of generation supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area,

transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.4, every offer of energy by a Market Participant from a generating Resource, an External Transaction purchase Resource and a Dispatchable Asset Related Demand Resource that is following economic dispatch instructions of the ISO will be utilized in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and locational Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the most recent power flow solution produced by the State Estimator, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission

line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Determination of Energy Offers Used in Calculating Real-Time Prices and Real-Time Reserve Clearing Prices.

(a) During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market.

(b) To determine the energy offers submitted to the New England Markets that shall be used during the Operating Day to calculate the Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall determine which generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources are following its economic dispatch instructions. A generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-Time Prices if:

(i) the applicable Supply Offer price submitted by a Market Participant for energy from the generating Resource or External Transaction purchase is less than or equal to the Dispatch Rate associated with that generating Resource or External Transaction purchase; and

(ii) the applicable Demand Bid price submitted by a Market Participant for energy from the Dispatchable Asset Related Demand Resource is greater than or equal to the Dispatch Rate associated with that Dispatchable Asset Related Demand Resource; and

(iii) the generating Resource, other than a Fast Start Generator, is operating above its Economic Minimum Limit; or

(iv) the Fast Start Generator is operating at or above its Economic Minimum Limit and the applicable Supply Offer price submitted by a Market Participant for energy from the Fast Start Generator is less than or equal to the Dispatch Rate associated with that Fast Start Generator; or

(v) the generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource is specifically requested to operate or reduce consumption by the ISO's dispatcher and the associated energy offers or bids submitted are otherwise eligible to be included in the calculation of Real-Time Locational Marginal Prices.

(c) In determining whether a generating Resource or External Transaction purchase satisfies the condition described in III.2.4(b), the ISO will determine the Supply Offer price associated with an energy offer by comparing the actual megawatt output of the generating unit or External Transaction purchase with the Market Participant's Supply Offer price curve for that generating unit or External Transaction purchase. Because of practical generator response limitations, a generating unit whose megawatt output is not more than ten percent above the megawatt level specified in the Supply Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

(d) In determining whether a Dispatchable Asset Related Demand Resource satisfies the condition described in III.2.4(b), the ISO will determine the Demand Bid price associated with a Demand Bid by comparing the actual megawatt consumption of the Dispatchable Asset Related Demand Resource with the Market Participant's Demand Bid price curve for that Dispatchable Asset Related Demand Resource. Because of practical Dispatchable Asset Related Demand Resource response limitations, a Dispatchable Asset Related Demand Resource whose megawatt consumption is greater than or equal to ninety percent of the megawatt level specified in the Demand Bid price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy demand bid price used in the calculation of Real-Time Prices shall not be lower than the applicable Dispatch Rate.

III.2.5 Calculation of Real-Time Nodal Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section

III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.8; and (5) the effect on transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed every five minutes, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5. shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes if the Minimum Generation Emergency was declared on a New England Control Area wide basis or shall be set equal to the Energy Offer Floor for all Nodes and External Nodes within a sub-region if the Minimum Generation Emergency was declared within the sub-region.

III.2.6 Calculation of Day-Ahead Nodal Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions

resulting from the load specifications submitted by Market Participants, Supply Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying a linear optimization method to minimize energy, congestion and transmission loss costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer or bid as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Node.

The process for clearing External Nodes differs from the process for clearing other Nodes in that, in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available generation at its Economic Maximum Limit, the technical

software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

- (i) All fixed External Transaction sales are considered to be dispatchable at the Energy Offer Cap;
 - (ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer or Increment Offer price cleared). Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line generation, Increment Offers or External Transaction purchases; and
 - (iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line generation, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.
- (c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide generation MW (including fixed External Transaction purchases) with all possible generation off and with all remaining generation at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic generation in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

- (i) All fixed External Transaction purchases are considered to be dispatchable at the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;
- (ii) If power balance is not reached in step (i), reduce all committed generation down proportionately by ratio of Economic Minimum Limits but not below Emergency Minimum Limits. If power balance is achieved prior to reaching Emergency Minimum Limits, set LMP values equal to the lowest offer price of all on-line generation; and

(iii) If power balance not achieved in step (ii), set LMP values to Energy Offer Floor and reduce all committed generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.

(a) The ISO shall calculate Zonal Prices for each Load Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets for each hour using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

(b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.

(c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.

(d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.

(e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.

(f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.

(g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones and Reserve Zones and add or subtract Reliability Regions, Load Zones and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency

response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

(h) In the event the ISO makes changes to a Reliability Region or Load Zone or adds or subtracts Reliability Regions and Load Zones, for settlement purposes and to the extent practicable, Load Assets that are physically located in one Reliability Region and electrically located within another Reliability Region shall be located within the Reliability Region to which they are electrically located.

(i) External Nodes are the nodes at which External Transactions settle. As appropriate and after consulting with Market Participants, the ISO will establish and re-configure External Nodes taking into consideration appropriate factors, which may include: tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices, and inter-regional trading impacts.

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer's knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer's company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer's annual load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require

customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of Real-Time Nodal Prices specified under Section III.2.5, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available generating Resources and Dispatchable Asset Related Demand Resources with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMSNR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve or local TMOR, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all generating Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The unit-specific Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a generating Resource shall be determined for each generating Resource that the ISO requires to reduce output in order to provide additional Operating Reserve or local TMOR and shall be equal to the difference between (i) the Real-Time Energy LMP at the generation

Node for the generating Resource and (ii) the offer price associated with the reduction of the generating Resource’s output necessary to create the additional Operating Reserve or local TMOR from the generating Resource’s expected output level if it had been dispatched in economic merit order.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the LP algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

<u>Requirement</u>	<u>Requirement Sub-Category</u>	<u>RCPF</u>
Local TMOR		\$250/MWh
System TMOR	minimum TMOR	\$500/MWh
	Replacement Reserve	\$250/MWh
System TMNSR		\$850/MWh
System TMSR		\$50/MWh

The RCPFs shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve Requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed every five minutes, using the ISO’s Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour to be used in settlements.

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes within the New England Control Area, which Nodes shall be identified by the ISO on its internet website. The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

- (i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;
- (ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;
- (iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;
- (iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and
- (v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.

(b) The ISO shall calculate and publish hourly Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation Clearing Prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices as soon as practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve

Clearing Prices and final Regulation Clearing Prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the

applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

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 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*.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this *Appendix A*, the provisions of *Appendix A* shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III.A.17.3 are also part of the Participants Agreement and cannot be modified in either *Appendix A* or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this *Appendix A* are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

- (a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this *Appendix A*). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its

identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

- (b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.
- (c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the External Market Monitor shall perform the following functions:

- (a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this *Appendix A*, in accordance with the provisions of Section III.A.17 of this *Appendix A*.

- (c) Conduct evaluations and prepare reports on its own initiative or at the request of others.
- (d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this *Appendix A*.
- (f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.
- (g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this *Appendix A*, as appropriate.
- (h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this *Appendix A*, the Internal Market Monitor shall perform the following functions:

- (a) Maintain *Appendix A* and consider whether *Appendix A* requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.
- (b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this *Appendix A*.
- (c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this *Appendix A*.
- (d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this *Appendix A*.
- (e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this *Appendix A*, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.
- (f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.
- (g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this *Appendix A*.
- (h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

- (i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this *Appendix A*.
- (j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this *Appendix A* are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

- (i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.
- (ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.
- (iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this *Appendix A*.
- (iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this *Appendix A*.
- (v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend *Appendix A* as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of

the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

- (i) Anti-competitive gaming of Resources;
- (ii) Conduct and market outcomes that are inconsistent with competitive markets;
- (iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;
- (iv) Actions in one market that affect price in another market;
- (v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this *Appendix A*, interfere with efficient market operation, both short-run and long-run; and
- (vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this *Appendix A*. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this *Appendix A*. If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

- (l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.
- (m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with *Appendix B* of this Market Rule 1.

- (n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this *Appendix A* for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule 1 (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this *Appendix A*. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this *Appendix A*, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under *Appendix B* of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

- (a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11. below:
- (b) Notwithstanding the foregoing or any other provision of this *Appendix A*, and as more fully described in Section III.B.3.2.6 of *Appendix B* to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3 Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4 Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this *Appendix A*, it may make a filing under §205 of the Federal Power Act (“§205”) with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor’s justification for imposing that mitigation measure.

III.A.2.4.5 Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this *Appendix A* or in *Appendix B* to this Market Rule 1.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant. In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. [Adjustments](#) to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this *Appendix A*, the Market Participant may contact the Internal Market Monitor to provide an explanation of increased cost. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least one hour prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least one hour prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment analyses if received by 6:00 p.m. the day prior to the Operating Day. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. [Any](#) request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market Participant's submission of the offer.

Any changes to fuel prices shall not be subject to the consultation provisions of this Section III.A.3.1. If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this *Appendix A* for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of cost-based Reference Levels pursuant to Section III.A.7.5 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher priced fuel available to the Resource, then within five business days the Market Participant must:

- (a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.
- (b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information within five business days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. The Reference Levels will be made available on a daily basis. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus \$2.50/MMbtu.

(b) Within five business days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with (i) an invoice for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the

operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price may be no greater than 110% of the fuel price reflected on the submitted invoice for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder.

(c) The Supply Offers for the associated Resource may be no greater than 110% and no less than 90% of the Reference Level calculated with the submitted fuel price.

(d) If, within a 12 month period, the requirements in sub-sections (b) or (c) are not met for a Resource, then a fuel price adjustment shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-sections (b) or (c) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2
2 or more	6

III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

- (a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
- (b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,
- (c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
- (d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

- (a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
- (b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or
- (c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

- (a) all Supply Offer parameters shall be reviewed for economic withholding;
- (b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;

- (c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five business days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

- (a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.3 "General Threshold Commitment Mitigation" apply, and;
- (b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Threshold Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Threshold Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval in the Day-Ahead Energy Market is any of the 24 hours for which pivotal supplier calculations are made. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to the clearing of the Day-Ahead Energy Market, prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

- (a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;
- (b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than \$25/MWh.

III.A.5.3. Calculation of Impact Tests in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.1 "General Threshold Energy Mitigation" compares two LMPs at a Resource's Node. The first LMP is calculated based on the Supply Offers submitted for all Resources. The second LMP is calculated through a simulation of the Day-Ahead Energy Market with the offer blocks associated with conduct violations of the pivotal supplier's Resources set to their Reference Levels.

A Supply Offer shall be determined to have no price impact for the purposes of Section III.A.5.5.1 "General Threshold Energy Mitigation" if:

- (a) the first LMP at the Resource's Node is less than the impact threshold, or;
- (b) the first LMP minus the Resource's Reference Level for each offer block is less than the impact threshold.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all

Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

- (a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
- (b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers submitted by a Lead Market Participant that is determined to be a pivotal supplier.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or \$100/MWh, whichever is lower. Offer block prices below \$25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or \$100/MWh, whichever is lower as determined by the day-ahead or real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or \$25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or \$25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. General Threshold Commitment Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource whose Lead Market Participant is determined to be a pivotal supplier.

III.A.5.5.3.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if any Start-Up Fee or No-Load Fee exceeds the Reference Level for that fee by 200% or more.

III.A.5.5.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters of its Supply Offer set to their Reference Levels, including all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.4. Constrained Area Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if any Start-Up Fee or the No-Load Fee is submitted with an increase greater than 25% above the Reference Level.

III.A.5.5.4.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all energy offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Local Reliability Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are committed to provide, or Resources that are required to remain online to provide, one or more of the following:

- (a) local first contingency protection or local second contingency protections;
- (b) VAR or voltage support; or
- (c) Special Constraint Resource Service

III.A.5.5.5.2. Conduct Test.

All financial parameters of Supply Offers will be evaluated to determine whether the following formula is true:

$$(\text{Low Load Cost at Offer} - \text{Low Load Cost at Reference Level}) = < \text{Commitment Cost Threshold}$$

Where,

$$\text{Commitment Cost Threshold} = 0.1 \text{ times Low Load Cost at Reference Level.}$$

Low Load Cost = the cost of operating the Resource at Economic Minimum calculated using the following formula:

$$(\text{Cold Start-Up Fee} + (\text{No Load Fee} * \text{minimum run time}) + (\text{Price of Energy at Economic Minimum} * \text{Economic Minimum} * \text{minimum run time}))$$

Low Load Cost at Offer = Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level = Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

Price of Energy at Economic Minimum = the price for energy at the Resource's Economic Minimum.

For Low Load Cost at Offer, the price for energy is the price from the Supply Offer. For Low Load Cost at Reference Level, the Reference Level of the offer block at Economic Minimum is used.

If a Resource's combined minimum run time and minimum down time exceed 24 hours, then the conduct test will use the greater of 24 hours or the Resource's minimum run time for the minimum run time.

If the (Low Load Cost at Offer – Low Load Cost at Reference Level) is greater than the Commitment Cost Threshold, then the conduct test is violated.

III.A.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 "General Threshold Energy Mitigation" or III.A.5.5.2 "Constrained Area Threshold Energy Mitigation" is in effect for the following duration:

- (a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:
 - (i) for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,
 - (ii) for constrained area energy mitigation, the Resource is not located within a constrained area.
- (b) in the Day-Ahead Energy Market, mitigation is in effect in each hour in which the impact test is violated.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.3 "General Threshold Commitment Mitigation", III.A.5.5.4 "Constrained Area Commitment Mitigation", or III.A.5.5.5 "Local Reliability Commitment Mitigation" is in effect for the following duration:

- (a) in the Real-Time Energy Market, mitigation starts either;
 - a. on the first hour a Resource is directed to remain on-line by the ISO or;
 - b. in all other cases, at the time of the decision to commit the Resource.
- (b) in the Day-Ahead Energy Market, mitigation starts at the beginning of the Operating Day, and;

- (c) for both the Real-Time Energy Market and Day-Ahead Energy Market, mitigation remains in effect:
- (i) for mitigation imposed pursuant to Sections III.A.5.5.3 or III.A.5.5.4, through the end of the Resource's Minimum Run Time; and, (ii) for mitigation imposed pursuant to Section III.A.5.5.5, through the end of the Resource's Minimum Run Time or through the end of the period that the Resource is needed for reliability, whichever is later.

III.A.5.8. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five business days of the applicable Operating Day. The ISO shall correct the error as part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.9. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., minimum run time, minimum down time, start time, and notification time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To

determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.1.1. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

- (a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.

- (b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.
- (c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Supply Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of a Supply Offer according to the following hierarchy, under which the first method that can be calculated is used:

- (a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
- (b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
- (c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

- (a) The cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
- (b) The Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
- (c) The Lead Market Participant requests the cost-based Reference Level.
- (d) During the previous 90 days:
 - (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;

- (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
- (iii) The Market Participant submits a fuel price pursuant to Section III.A.3.4.

For the purposes of this subsection:

- i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.
- ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.
- iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.
- iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar days (weekday or weekend day), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant through the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

- (a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".
- (b) Costs must be documented.
- (c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible.
- (d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.
- (e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:
 - (i) Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and
 - (ii) Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy:

(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

- (a) emissions limits;
- (b) water storage limits; and,
- (c) other operating permits that limit production of energy.

No-Load:

(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up:

(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. Determination of Offer Competitiveness During Shortage Event.

The Internal Market Monitor shall evaluate the competitiveness of the Supply Offer of each Resource with a Capacity Supply Obligation that is off-line during a Shortage Event, as described below. The evaluation for competitiveness shall be performed on Supply Offers in the Day-Ahead Energy Market and 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 Sections III.A.5.5.1 and III.A.5.5.3 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 Sections III.A.5.5.2 and III.A.5.5.4.

- (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 Fees 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.8 (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.8 (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.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor Demand Resources as outlined below:

- (a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.
- (b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The

average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

- (c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$$(\text{LMP}_{\text{real time}} / \text{LMP}_{\text{day ahead}}) - 1.$$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

- (i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.
- (ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.
- (iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England

Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

- (a) [Reserved].
- (b) Section III.13.1.2.2.5.2 "Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity."
- (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.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner’s scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this *Appendix A*. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants’ obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer *Appendix B* in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.

Article 5 of the form of Cost-of-Service Agreement in *Appendix I* to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Filing Right.

If either (a) as a result of mitigation applied to a Resource under this *Appendix A* for all or part of one or more Operating Days, or (b) in the absence of mitigation, despite having submitted a Supply Offer at the energy offer cap specified in Section III.1.10.1.A(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 the duration of the mitigation event, 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.15.2. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource for the duration of the mitigation event exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource for the duration of the mitigation event exceeded the costs as reflected in the Supply Offer at the energy offer cap; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that

resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.

III.A.15.4. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in *Appendix D* to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.
- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary

remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this *Appendix A*, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

- (a) the opportunity costs associated with Demand Reduction Offers;
- (b) the accuracy of Demand Response Baselines;
- (c) the method used to achieve a demand reduction, and;
- (d) the accuracy of reported demand levels.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this *Appendix A* and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this *Appendix A*.

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this *Appendix A*.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC

costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of *Appendix A*. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

- (i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.
- (ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.
- (iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.
- (iv) Review and assessment of the effectiveness of *Appendix A* and the administration of *Appendix A* by the Internal Market Monitor for consistency and compliance with the terms of *Appendix A*.
- (v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

- (a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;
- (b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;
- (c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,

- (d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets (“authorized government agencies”). With respect to state regulatory bodies and state attorneys general (“authorized state agencies”), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten business days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market

Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as *Exhibit 5*.

III.A.18.2. Additional Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony

or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of *Appendix A*, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

- (A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.
- (B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

- (D) The referral is to include, but need not be limited to, the following information
- (1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);
 - (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
 - (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
 - (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
 - (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;
 - (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
 - (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

- (A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.
- (B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal

Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

- (C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information.
 - (1) A detailed narrative describing the perceived market design flaw(s);
 - (2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;
 - (3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;
 - (4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21 Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1 Offer Review Trigger Prices.

For each new resource type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3 or III.13.1.4.2.4 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1 Offer Review Trigger Prices for the Eighth Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017) shall be as follows:

Resource Type	Offer Review Trigger Price (\$/kW-month)
Combustine Turbine	\$10.00
Combined Cycle Gas Turbine	\$11.00
Biomass	\$24.00
On-Shore Wind	\$14.00
Real-Time Demand Response	\$1.00
Energy Efficiency	\$0.00
All Other Resource Types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different resource types, the resource shall have an Offer Review Trigger Price equal to the highest of the applicable Offer Review Trigger Prices.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the resource type of the External Resource. For any other New Import Capacity Resource, the Offer Review Trigger Price shall be \$0.00/kW-month.

III.A.21.1.2 Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the resource types listed above shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For new generation resources, the methodology used to develop the Offer Review Trigger Price is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model, rounded to the nearest whole dollar value. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected

of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For new energy efficiency resources, the methodology used to develop the Offer Review Trigger Price shall be the same as that used for new generation resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the programs' life.

(d) For new Real-Time Demand Response resources, the methodology used to develop the Offer Review Trigger Price is based on an analysis of the incremental operating costs associated with the demand response business activities of selected industry firms engaged primarily in the demand response business, as reported in their Form 10k filings with the U.S. Securities and Exchange Commission. The Internal Market Monitor will review data regarding annual customer totals (MW) and operating costs (cost of sales), allocated marketing and sales expense, and allocated administrative and general expense for the three preceding consecutive years. The incremental MW and the total incremental operating costs for each firm is calculated and the incremental cost is then divided by the incremental MW to estimate the incremental revenues required to cover the cost of new Real-Time Demand Response MW. The Offer Review Trigger Price is set to the lowest calculated incremental revenue value for the selected firms during the studied years rounded to the nearest whole number.

III.A.21.2 New Resource Offer Floor Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price, as described in this Section III.A.21.2.

(a) For a new capacity resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 or III.13.1.4.2.4, the New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price applicable to the relevant resource type.

(b) For a new capacity resource that does submit a request to submit offers in the Forward Capacity

Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 and III.13.1.4.2.4, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate.

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a new Real-Time Demand Response resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred by the Demand Response Provider to acquire the Real-Time Demand Response resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the Real-Time Demand Response resource.

(iii) For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer price is consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price.

(vi) If the Internal Market Monitor determines that the requested offer price is not consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1.

III.A.21.3 Special Treatment of Certain Out-of-Market Capacity Resources in the Eighth

Forward Capacity Auction.

For the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017), the provisions of Sections III.A.21.1 and III.A.21.2 shall also apply to certain resources that cleared in the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2015) and/or the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2016), as follows:

(a) This Section III.A.21.3 shall apply to: (i) any capacity clearing in the sixth or seventh Forward Capacity Auction as a New Generating Capacity Resource or New Import Capacity Resource designated as a Self-Supplied FCA Resource; and (ii) any capacity clearing in the sixth or seventh Forward Capacity Auction from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at prices found by the Internal Market Monitor to be not consistent with either: (a) the resource's long run average costs net of expected net revenues other than capacity revenues for a New Generating Capacity Resource and a New Demand Resource or (b) opportunity costs for a New Import Capacity Resource.

(b) For the eighth Forward Capacity Auction, the capacity described in subsection (a) above shall receive Offer Review Trigger Prices as described in Section III.A.21.1 and New Resource Offer Floor Prices as described in Section III.A.21.2. These values will apply to such capacity in the conduct of the eighth Forward Capacity Auction as described in Section III.13.2.3.2.

(c) For the eighth Forward Capacity Auction, the Project Sponsor or Lead Market Participant for such capacity may be required to comply with some or all of the qualification provisions applicable to new resources described in Section III.13.1. These requirements will be determined by the ISO on a case-by-case basis in consultation with the Project Sponsor or Lead Market Participant.

(d) For any capacity described in subsection (a) above that does not clear in the eighth Forward Capacity Auction:

(i) any prior election to have a Capacity Clearing Price and Capacity Supply Obligation continue to apply for more than one Capacity Commitment Period made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 shall be terminated as of the beginning of the Capacity Commitment Period associated with the eighth FCA (beginning June 1, 2017); and

(ii) after the eighth Forward Capacity Auction, such capacity will be deemed to have never been previously counted as capacity, such that it meets the definition, and must meet the requirements, of a new capacity resource for the subsequent Forward Capacity Auction in which it seeks to participate.

1 UNITED STATES OF AMERICA
2 BEFORE THE
3 FEDERAL ENERGY REGULATORY COMMISSION
4
5

6)
7 ISO New England Inc. and) Docket No. ER13-_____-000
8 New England Power Pool)
9)

10
11 JOINT TESTIMONY OF ROBERT G. ETHIER
12 AND CHRISTOPHER A. PARENT
13

14 **Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.**

15
16 A: *Dr. Ethier:* My name is Robert G. Ethier. I am employed by ISO New England
17 Inc. (the “ISO”) as Vice President of Market Development. My business address
18 is One Sullivan Road, Holyoke, Massachusetts 01040.

19
20 *Mr. Parent:* My name is Christopher A. Parent. I am the Manager of the Market
21 Development Department at the ISO. My business address is One Sullivan Road,
22 Holyoke, Massachusetts 01040.

23
24 **Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND**
25 **QUALIFICATIONS.**

26
27 A: *Dr. Ethier:* I have a Bachelor of Arts degree in Economics from Yale University,
28 a Masters in Resource Economics from Cornell University, and a Ph.D. in
29 Resource Economics from Cornell University. I have more than ten years of
30 experience in the energy and utility industry. Before 2000, I was a Senior

1 Associate at Stratus Consulting with the responsibility of energy market
2 modeling. Since 2000, I have worked with the ISO in various roles. I was
3 responsible for Market Monitoring for nearly four years and Resource Adequacy
4 for more than two years before becoming Vice President of Market Development
5 in July 2008.

6
7 *Mr. Parent:* I have been with the ISO since July 2004 and have held various
8 positions within the organization, including Supervisor of Hourly Settlements,
9 Supervisor of Business Analysis, and Manager of Business Development. I was
10 also Manager, Quality & Business Process Development reporting to the Chief
11 Operating Officer until December 2009 when I became the Manager of the
12 Market Development Department. In my present position, I am responsible for
13 coordinating the market development work at the ISO. By working closely with
14 my staff, internal business units and external stakeholders on proposed changes to
15 the market design, I help to ensure that proposed solutions to market issues
16 address the identified scope efficiently and effectively and that they are fully
17 vetted through the internal ISO review process and the external stakeholder
18 review process.

19

20 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

21

22 A: The primary purpose of the testimony is to explain the changes made to the
23 market rules to provide more flexibility for Market Participants to structure and

1 modify their Supply Offers¹ for generating resources and their Demand Bids for
2 Dispatchable Asset Related Demand (the “Offer Flexibility Changes”).

3

4 The Offer Flexibility Changes can be divided into five categories:

5 (1) The ability to modify the cost-related parameters of a Supply Offer or a

6 Demand Bid for a Dispatchable Asset Related Demand after the initial

7 Reserve Adequacy Analysis (“RAA”) process is completed;

8 (2) The ability to submit cost-related parameters of a Supply Offer or a Demand

9 Bid for a Dispatchable Asset Related Demand that may vary by hour, rather

10 than requiring these parameters to be the same for all hours of an Operating

11 Day;

12 (3) Modification of the existing method of implementing self-scheduling that is

13 based on modifying a generating resource’s Economic Minimum Limit to

14 indicate a Self-Schedule level, to a method that relies on the Market

15 Participant’s ability to submit hourly Supply Offers and change their Supply

16 Offers in real time;

17 (4) The ability to submit a negative offer for External Transactions and the

18 energy Blocks for a Supply Offer, Demand Bid, Increment Offer and

19 Decrement Bid, and;

20 (5) Clarification and clean-up changes including removing defined terms that are

21 no longer applicable, adding defined terms for Supply Offer parameters and

22 clarifications to language related to Supply Offers, Demand Bids and

¹ Capitalized terms used but not defined in this testimony are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff (“ISO Tariff”) and the Participants Agreement.

1 External Transactions.

2 Unless required for precision, the different types of offers that are affected by the
3 Offer Flexibility Changes often are referred to simply as “offers” in the remainder
4 of this testimony, rather than repeatedly using the longer, defined terms.

5

6 **BACKGROUND**

7

8 **Q: DESCRIBE THE CURRENT RULES GOVERNING WHEN SUPPLY**
9 **OFFERS AND DEMAND BIDS FOR THE ENERGY MARKET CAN BE**
10 **SUBMITTED AND MODIFIED.**

11

12 **A:** Under the existing rules, the submission window for Supply Offers and Demand
13 Bids in the Day-Ahead Energy Market closes at 10:00 a.m. of the day prior to the
14 applicable electric Operating Day. The ISO clears the Day-Ahead Energy Market
15 and posts the market results by 1:30 p.m. Following the posting of the Day-
16 Ahead Energy Market results, the Re-Offer Period submission window is open
17 between 1:30 p.m. and 2:00 p.m. During the Re-Offer Period, Market
18 Participants may submit changes to Supply Offers and Demand Bids (for
19 Dispatchable Asset Related Demand only). Following the Re-Offer Period,
20 around 2:00 p.m., the ISO conducts an initial RAA, using Supply Offers and
21 Demand Bids submitted for the Day-Ahead Energy Market and modified during
22 the Re-Offer Period. The initial RAA process produces an operating plan for the
23 upcoming Operating Day by determining whether it is necessary, to satisfy
24 reliability criteria, to schedule resources in addition to those that were scheduled
25 through the Day-Ahead Energy Market clearing process. The initial RAA process
26 is completed around 5:00 p.m. and Market Participants are notified if their
27 resources have been scheduled to operate for the upcoming Operating Day. The

1 Supply Offers and Demand Bids used in the initial RAA process are also used in
2 any subsequent RAA processes and for the real-time dispatch of generating
3 resources and Dispatchable Asset Related Demand. There is no opportunity to
4 change the cost-related parameters of a Supply Offer or Demand Bid after the Re-
5 Offer Period; however, some other parameters can be re-declared by a Market
6 Participant in real time to accurately reflect the physical characteristics of the
7 resource.

8

9 **Q: DESCRIBE THE CURRENT RULES GOVERNING WHEN SUPPLY**
10 **OFFERS FOR THE REGULATION MARKET CAN BE SUBMITTED**
11 **AND MODIFIED.**

12

13 A: Under the existing rules, Supply Offers for Regulation are submitted prior to the
14 close of the Re-Offer Period. Supply Offers for Regulation cannot be modified
15 after the close of the Re-Offer Period; however, some of the other parameters can
16 be re-declared by the Market Participant in real time to reflect changes to the
17 physical characteristics of the resource.

18

19 **Q: DESCRIBE THE CURRENT STRUCTURE OF SUPPLY OFFERS AND**
20 **DEMAND BIDS**

21

22 A: Supply Offers and Demand Bids for Dispatchable Asset Related Demand include
23 a number of parameters. Some of these parameters can be specified with an
24 hourly granularity within the Supply Offers (*e.g.*, Economic Maximum Limit,
25 Economic Minimum Limit) and Demand Bids (*e.g.*, Maximum Consumption
26 Limit, Minimum Consumption Limit) while other parameters (*e.g.*, Blocks, Start-
27 Up Fee, No Load Fee, Regulation offer and quantity) are required to be specified

1 at a daily granularity (*i.e.*, one value for all hours of the Operating Day).

2

3 **Q: DESCRIBE THE LOWEST PRICE FOR ENERGY THAT CAN BE**
4 **SUBMITTED INTO THE ENERGY MARKET**

5

6 A: External Transactions and the Blocks of a Supply Offer, Demand Bid, Increment
7 Offer and Decrement Bid for energy cannot be offered for less than \$0/MWh.

8

9 **Q: DESCRIBE THE CURRENT METHOD FOR SELF-SCHEDULING**
10 **GENERATING RESOURCES AND DISPATCHABLE ASSET RELATED**
11 **DEMAND.**

12

13 A: Market Participants may request, with at least 30 minutes lead time, that a
14 resource be self-scheduled to be online at a specific minimum output level or
15 minimum consumption level or, for resources already operating, requesting a
16 different minimum output level or minimum consumption level than the level at
17 which the resource is operating. Specifying a change to the minimum level of
18 operation is accomplished by adjusting the Economic Minimum Limit of a
19 generating resource or the Minimum Consumption Limit of a Dispatchable Asset
20 Related Demand. The ISO will accept a request to self-schedule a resource if it
21 does not create a reliability problem.

22

23 For a generating resource, a self-schedule reflects an amount of “must-take”
24 energy into the market (*i.e.*, a willingness to operate at any price) and assuming
25 the Economic Minimum Limit is set higher than the generating resource’s lowest
26 Economic Minimum Limit, the self-schedule decreases the generating resource’s
27 dispatchable range (*i.e.*, the difference between the Economic Maximum Limit

1 and Economic Minimum Limit) that is available to for the ISO to dispatch
2 without taking administrative actions to cancel the self-schedule request.

3

4 **1. REAL-TIME OFFER CHANGES TO SUPPLY OFFERS AND**
5 **DEMAND BIDS**

6

7 **Q: PLEASE EXPLAIN THE RULE CHANGES THAT WILL ALLOW**
8 **SUPPLY OFFERS AND DEMAND BIDS TO BE FURTHER REVISED IN**
9 **REAL-TIME.**

10

11 A: Under the Offer Flexibility Changes, Market Participants will be able to change
12 the cost-related parameters of their Supply Offers for generating resources and
13 Demand Bids for Dispatchable Asset Related Demand after the initial RAA
14 process is complete until 30 minutes prior to the hour in which the Supply Offer
15 or Demand Bid would apply.

16

17 Specifically, for generating resources, Market Participants will be able to modify
18 the energy Blocks, Start-Up Fee, No-Load Fee, fuel type and the Regulation
19 Supply Offer price and quantity. For Dispatchable Asset Related Demand,
20 Market Participants will be able to modify the energy Blocks of the Demand Bid.

21

22 **Q: WHAT IS THE REASON FOR ALLOWING MODIFICATIONS TO**
23 **SUPPLY OFFERS AND DEMAND BIDS AFTER THE INITIAL RAA**
24 **PROCESS?**

25

26 A: Under the existing market rules the final opportunity to change cost related
27 parameters is at 2:00 p.m. on the day prior to the Operating Day (*i.e.*, the Re-Offer
28 Period). However, these cost-related parameters could change significantly (both
29 up and down) after Re-Offer Period. When this occurs, the Supply Offer or

1 Demand Bid becomes “stale” and no longer reflects the resource’s costs into the
2 market.

3

4 **Q: WHAT ARE THE IMPLICATIONS TO THE MARKET OF A SUPPLY**
5 **OFFER THAT IS “STALE?”**

6

7 A: A fundamental principle of efficient wholesale electricity market design is that the
8 energy price should equal the incremental cost of the marginal resource (*i.e.*, the
9 last resource that is dispatched). A “stale” Supply Offer may result in an energy
10 price that does not reflect the marginal resource’s incremental energy costs. In
11 addition, “stale” Supply Offers can also impact the evaluation of which resources
12 to schedule through the RAA process, potentially resulting in higher cost
13 resources being scheduled over lower cost resources.

14

15 “Stale” Supply Offers can also result in some Market Participants with generating
16 resources having financial incentives that differ from a resource’s obligation to
17 follow ISO dispatch.

18

- 19 • In conditions where a generating resource’s costs have decreased , a Market
20 Participant has an incentive to self-schedule the resource’s output (reducing its
21 dispatchable range), rather than leaving the resource’s output level to be
22 determined by the economic dispatch process. In conditions where a
23 resource’s costs have increased, a Market Participant has a financial incentive
24 not to operate or under produce rather than leaving the resource’s output level
25 to be determined by the economic dispatch process.

25

1 **Q: PLEASE PROVIDE AN EXAMPLE OF THE POTENTIAL MARKET**
2 **INEFFICIENCY ASSOCIATED WITH A “STALE” SUPPLY OFFER.**

3
4 A: Assume that a natural gas-fired resource has an energy offer for a Block that is
5 submitted during the Re-Offer Period of \$30/MWh and an oil-fired resource has
6 an energy offer for a Block that was submitted during the Re-Offer Period of
7 \$80/MWh. If the price of natural gas increases in real time so that the marginal
8 energy cost for the gas-fired resource has risen to \$95/MWh, without the ability to
9 modify the Supply Offer in real time, the gas-fired resource will appear less
10 expensive than the oil-fired resource and be dispatched first. However, the oil-
11 fired resource has lower costs and should be dispatched before the gas-fired
12 resource (*i.e.*, economically efficient dispatch).

13
14 Assuming that the gas-fired resource is the marginal resource, the energy
15 component of the Real-Time LMP would be \$30/MWh, based upon a forward
16 expectation of the gas price, not the actual cost of gas in real-time, sending the
17 wrong signal to the electric markets through the real-time LMP and creating a
18 disconnect between the marginal cost in electric markets and marginal cost in the
19 fuel markets. Additionally, in these circumstances, the Market Participant with
20 the gas-fired resource lacks a strong financial incentive in the energy market to
21 meet its obligation to follow dispatch instructions since each MWh of operation
22 would result in a loss of \$65/MWh (\$95/MWh minus \$30/MWh)

23

1 **Q: DO THE PROPOSED CHANGES TO ALLOW FOR MODIFICATIONS**
2 **TO SUPPLY OFFERS AND DEMAND BIDS IN REAL-TIME CORRECT**
3 **THESE MARKET INEFFICIENCIES AND RESOURCE INCENTIVE**
4 **PROBLEMS?**
5

6 A: Yes. The Offer Flexibility Changes will reduce the potential for this type of
7 mismatch between financial incentives and dispatch instructions. With the ability
8 for Market Participants to modify their Supply Offers and Demand Bids after the
9 initial RAA process is complete into real-time, the expectation is that the gas-fired
10 resource's offer of Energy in their Block would be revised to \$95/MWh, resulting
11 in the oil-fired resource being dispatched first. Assuming the oil-fired resource
12 was marginal, the energy component of the Real-Time LMP would be \$80/MWh
13 consistent with the cost of the marginal fuel (oil) in the market. The gas-fired
14 resource would be dispatched if their more expensive energy was required and,
15 assuming that the gas-fired resource was marginal, would set the energy
16 component of the Real-Time LMP at \$95/MWh consistent with the marginal fuel
17 (natural gas).

18
19 Allowing Supply Offers and Demand Bids to be modified after the initial RAA
20 process is complete will better ensure that market results, Market Participants'
21 financial incentives and the requirement for resources to follow dispatch
22 instructions are aligned.
23

1 **2. HOURLY SUPPLY OFFER AND DEMAND BID PARAMETERS**
2

3 **Q: EXPLAIN THE CHANGES THAT PROVIDE THE ABILITY TO SUBMIT**
4 **SUPPLY OFFERS AND DEMAND BIDS WITH PARAMETERS THAT**
5 **VARY BY HOUR RATHER THAN APPLYING THE SAME**
6 **PARAMETERS TO EVERY HOUR OF AN OPERATING DAY.**
7

8 A: The Offer Flexibility Changes allow Market Participants to submit a Supply Offer
9 or Demand Bid with cost-related parameters that may vary by hour, rather than
10 requiring these cost related parameters to be the same for all hours of an
11 Operating Day for use in the Day-Ahead Energy Market, RAA process,
12 Regulation market and Real-Time Energy Market.

13
14 Specifically, for generating resources, Market Participants will now be able to
15 submit hourly values in a Supply Offer for the Start-Up Fee, the No-Load Fee,
16 fuel type, each energy Block and the Regulation Supply Offer price and quantity.
17 For Dispatchable Asset Related Demand, Market Participants will now be able to
18 submit hourly values for their energy Blocks.

19
20 **Q: WHAT IS THE REASON FOR ALLOWING CERTAIN COST RELATED**
21 **PARAMETERS TO BE SUBMITTED HOURLY RATHER THAN DAILY?**
22

23 A: Currently, Market Participants can represent a generating resource’s costs through
24 the submission of a daily Start-Up Fee, No-Load Fee and energy Block for the
25 Energy Market, daily values for the Regulation Supply Offer price and quantity
26 and Dispatchable Asset Related Demand costs through a daily energy Block for
27 the Energy Market. However, the costs for resources may vary over the course of
28 the Operating Day.

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Q: ARE THERE POTENTIAL MARKET EFFICIENCY ISSUES ASSOCIATED WITH SUPPLY OFFERS AND DEMAND BIDS THAT CANNOT BE VARIED BY HOUR DURING A DAY?

A: Yes. For example, the differences in timing between the electric and natural gas days create the potential for a Market Participant to procure natural gas at two different prices for consumption across one electric day. Under the existing rules, if a Market Participant incurs different fuel prices for a given electric day, these differing costs cannot be directly reflected in a single daily Supply Offer or Demand Bid.

Rather, Market Participants seeking to reflect these different costs must pursue a non-optimal approach to reflecting their varying costs in their Demand Bids or Supply Offers by, for example, averaging the fuel costs, using the highest fuel costs, weighting the costs or applying some factor which reflects a risk premium. Any such approach is inherently less efficient than providing Market Participants with the ability to submit Supply Offers and Demand Bids that reflect hourly variations in their costs.

For the same reasons discussed above with respect to the submission of offers in real time, providing Market Participants with the ability to submit Supply Offers and Demand Bids that vary by hour will avoid instances in which the day-ahead LMPs and real-time LMPs and Real-Time Reserve Clearing Prices may not properly reflect the cost of the marginal resource. Allowing Supply Offers and

1 Demand Bids to vary by hour will better ensure that market results, Market
2 Participants' financial incentives and the requirement for resources to follow
3 dispatch instructions are aligned.

4

5 **3. CHANGE TO THE CURRENT SELF-SCHEDULE STRUCTURE**

6

7 **Q: PLEASE DESCRIBE THE CHANGES TO THE SELF-SCHEDULING**
8 **STRUCTURE.**

9

10 A: The Offer Flexibility Changes eliminate the use of the Economic Minimum Limit
11 as the mechanism through which a Market Participant indicates a desired
12 minimum output level of a generating resource (*i.e.*, requests a self-schedule).
13 Rather, the Economic Minimum Limit is proposed to be a more static value
14 established based upon the physical design characteristics, environmental
15 regulations and licensing limits of the generating resource. Market Participants
16 will use the proposed capability to submit hourly energy Blocks for the Day-
17 Ahead Energy Market and Re-Offer Period and revised energy Blocks for the
18 Real-Time Energy Market to express their desire to operate at various output
19 levels.

20

21 While the language describing the current method for Market Participants to self-
22 schedule generating resources was clarified, there are no changes to the current
23 practice that allows Market Participants to schedule their resources (*i.e.*, self-
24 commit their resources and go from an offline state to an online state) to provide
25 energy at their Economic Minimum Limit in the Day-Ahead Energy Market, Re-
26 Offer Period and Real-Time Energy Market subject to approval by the ISO. Also,

1 while the language describing how a request for a Dispatchable Asset Related
2 Demand to be self-scheduled has been clarified; these will not change how a
3 Dispatch Asset Related Demand is self-scheduled.

4

5 **Q: DOES THE NEW SELF-SCHEDULE STRUCTURE STILL ALLOW**
6 **INTRA-HOUR TREATMENT?**

7

8 A: Yes. In order to carry forward the existing ability for Market Participants to
9 request a self-schedule within an hour, the Offer Flexibility Changes allow
10 Market Participants, after the Real-Time Offer Change deadline defined in
11 Section III.1.10.9(b) has passed, to request that a generating resource be
12 dispatched at a specific output level. However, rather than modifying the
13 generating resource's Economic Minimum Limit, as is done today, this request
14 will be treated as if the Market Participant modified the resource's offer for the
15 energy Blocks at the Offer Floor Price for the quantity associated with the
16 requested output level. This allows Market Participants to make intra-hour
17 changes to their Supply Offers similar to the current self-schedule rules, but will
18 not result in a decrease in the resource's dispatchable range. This change only
19 applies to the Real-Time Energy Market.

20

21 **Q: WHAT IS THE PURPOSE OF CHANGING THE SELF-SCHEDULE**
22 **STRUCTURE?**

23

24 A: Under the current rules, the Economic Minimum Limit is treated as the minimum
25 output level at which a resource will be dispatched, which reduces the
26 dispatchable range of a resource when the resource adjusts its Economic

1 Minimum Limit through a self-schedule request. This decrease in dispatchable
2 range can artificially create excess generation conditions (also called a Minimum
3 Generation Emergency) on the system or, when the local transmission system is
4 constrained require the ISO to take administrative actions (*e.g.*, manually
5 curtailing resources), which generally are not properly reflected fully in the price,
6 to resolve the constraint and under extreme conditions to administratively set the
7 energy price to \$0/MWh.

8
9 While the proposed change to self-schedule treatment does not eliminate the need
10 to take administrative actions or use administrative pricing, these actions should
11 only need to be taken in the Day-Ahead Energy Market and in the Real-Time
12 Energy Market when there is a true excess generation condition on the system, not
13 one which is artificially created by increasing generating resources' Economic
14 Minimum Limits through self-schedule requests.

15
16 Under the current rules, system operators can only access the dispatchable range
17 between the Economic Minimum Limit (unadjusted by self-schedule requests)
18 and the Economic Minimum Limit (adjusted for self-schedule requests) by taking
19 administrative actions. By eliminating the ability to adjust the Economic
20 Minimum Limit for self-schedule requests, system operators will have access to
21 the full capability of the resource down to its Economic Minimum Limit
22 (unadjusted by self-schedule requests) without requiring administrative actions.

23

1 It is expected that these changes will reduce the frequency of administrative
2 actions being taken to address system excess generation constraints and improve
3 the pricing leading into these types of events because the unit dispatch system will
4 be able to dispatch all resources down to their Economic Minimum Limit
5 (unadjusted by self-schedule requests) before administrative actions need to be
6 taken. It is also expected that these changes will help with more localized
7 transmission constraints for similar reasons.

8

9 **Q: PLEASE PROVIDE AN EXAMPLE OF THIS ADVERSE OUTCOME.**

10

11 A: Assume that a Market Participant with a resource with an Economic Minimum
12 Limit (unadjusted for a self-scheduled request) of 50 MW and Economic
13 Maximum Limit of 300 MW submits a self-schedule that adjusts the Economic
14 Minimum Limit of a resource in the Day-Ahead Energy Market to 275 MW
15 resulting in the resource clearing at 275 MW. The action of self-scheduling
16 reduces the dispatchable range of the resource from 250 MW to only 25 MW.
17 Under the current rules the only way for the ISO to access the full dispatchable
18 range of the resource is to declare a Minimum Generation Emergency (*i.e.*, take
19 administrative actions).

20

21 Under the Offer Flexibility Changes, the Market Participant would be able to self-
22 schedule the resource by submitting a Supply Offer (and revising the Supply
23 Offer in real time if desired) that is lower than the real-time price. If necessary,
24 the ISO would be able to dispatch the resource within its full dispatchable range

1 without having to declare a Minimum Generation Emergency.

2

3 **4. SUBMISSION OF ENERGY OFFERS BELOW \$0/MWH**

4

5 **Q: PLEASE DESCRIBE THE CHANGE THAT ALLOWS FOR THE**
6 **SUBMISSION OF ENERGY OFFERS BELOW \$0/MWH.**

7

8 A: Under the existing market rules, the lowest energy offer that can be submitted is
9 \$0/MWh. The Offer Flexibility Changes will allow Market Participants to submit
10 offers as low as negative \$150/MWh (*i.e.*, Energy Offer Floor) for External
11 Transactions and the energy Blocks of Supply Offers, Demand Bids, Increment
12 Offers and Decrement Bids.

13

14 In addition, the ISO clarified that for fixed External Transaction purchases (which
15 are unpriced imports of energy from other control areas) the assumed offer will be
16 set at negative \$150/MWh, rather than at \$0/MWh.

17

18 **Q: HOW WAS THE LEVEL OF THE NEW OFFER FLOOR ESTABLISHED?**

19

20 A: The Offer Floor Price is set at a level that provides Market Participants adequate
21 capability to reflect negative costs in the energy market so that offers that are
22 currently submitted at \$0/MWh can be adequately differentiated. An Energy
23 Offer Floor of negative \$150/MWh accommodates the needs of Market
24 Participants with resources that can operate economically (or can increase
25 consumption) at very low energy prices and is more consistent with the minimum
26 energy offer levels used in other regions (which also have negative offer floors).

27

1 The ISO will monitor offer behavior to ensure that the Energy Offer Floor is low
2 enough for Market Participants to adequately differentiate their desire to operate
3 their resources during periods of system excess generation or local transmission
4 constraints and will propose additional modifications to further reduce the offer
5 floor if appropriate.

6

7 **Q: WHAT ARE THE BENEFITS OF LOWERING THE ENERGY OFFER**
8 **FLOOR?**

9

10 A: The primary benefit to modifying the Energy Offer Floor to allow Market
11 Participants to submit negative offers is to allow Market Participants to indicate
12 their willingness to produce (or consume) at negative prices improving the ability
13 of the ISO to economically prioritize the selection of resources to reduce output
14 (or increase consumption) based on offers as low as negative \$150/MWh and
15 reduce the likelihood of dispatching resources offered at \$0/MWh on a *pro rata*
16 basis or through some other administrative mechanism.

17

18 **Q: THESE CHANGES SEEM TO COMPLEMENT SOME OF THE OTHER**
19 **PROPOSED MODIFICATIONS. COULD YOU EXPLAIN THIS**
20 **FURTHER?**

21

22 A: Yes. This change does complement the modifications made to the self-schedule
23 rules for generating resources and the ability of Market Participants to submit
24 modifications to Supply Offers and Demand Bids in real time.

25

26 As discussed above, allowing Markets Participants to submit negative offers
27 allows resources that typically offer at \$0/MWh to differentiate their desire to

1 operate (or consume). Also, as discussed above, having greater access to the
2 dispatchable range of resources allows the dispatch software to dispatch resources
3 down to their typical Economic Minimum Limit (unadjusted for any self-schedule
4 requests), delaying the need to take administrative actions to resolve excess
5 generation conditions and allowing prices to reflect the marginal cost of the
6 resource being dispatched. The combination of providing greater access to the
7 dispatchable range of resources and the ability for these resources to have
8 differentiated offers below \$0/MWh will allow prices to better reflect the
9 marginal costs of the resource being dispatched under these types of conditions
10 and reduce the need to use administrative pricing.

11

12 In addition to the changes to the self-scheduling rules, the rule changes that allow
13 modifications to Supply Offers and Demand Bids in real time provide Market
14 Participants the opportunity to revise their offers in real time as excess generation
15 conditions are approaching, including allowing Market Participants to specify
16 negative offers going into these types of events.

17

18 **Q: WHY IS THE LMP SET AT THE ENERGY OFFER FLOOR DURING A**
19 **SYSTEM-LEVEL MINIMUM GENERATION EMERGENCY?**

20

21 A: When the ISO declares a Minimum Generation Emergency because of expected
22 excess generation on the system, the real-time LMP is set to negative \$150/MWh.
23 This price needs to be set at the Energy Offer Floor to provide a strong incentive
24 for all generating resources to follow dispatch down to their Emergency
25 Minimum Limit (and Dispatch Asset Related Demand to follow dispatch up),

1 even those generating resources which may have been offered at the Energy Offer
2 Floor or may not be able to follow dispatch directly in real time.

3

4 **5. ADDITIONAL CHANGES**

5

6 **Q: COULD YOU EXPLAIN THE NEW DEFINED TERMS ADDED TO THE**
7 **TARIFF?**

8

9 **A:** Yes. The Offer Flexibility Changes includes the addition of the following defined
10 terms related to the submission of Supply Offer and Demand Bids:

- 11 • Energy Offer Cap is added as a formal defined term and replaces the direct
12 references to the \$1,000/MWh limit on the offer submitted on External
13 Transactions and the offer of the energy Block for Supply Offers, Demand
14 Bids, Increment Offers and Decrement Bids
- 15 • Minimum Run Time is a parameter included within a Supply Offer for a
16 generating resource and defines the minimum duration for which the ISO
17 must schedule a resource to operate from the point it is expected to reach its
18 Economic Minimum Limit.
- 19 • Minimum Down Time is a parameter included within a Supply Offer for a
20 generating resource and defines the duration which a resource must remain
21 offline before the ISO can schedule the resource to be back at its Economic
22 Minimum Limit.
- 23 • Reserve Adequacy Analysis (or “RAA”) was added as a defined term to
24 define the process which the ISO runs after the Re-Offer Period to ensure that

1 there are adequate resources available to meet the operating constraints of the
2 system.

3

4 **Q: PLEASE DESCRIBE THE CHANGES TO REMOVE CERTAIN**
5 **DEFINITIONS.**

6

7 A: Yes. The Offer Flexibility Changes also included the elimination of Cold
8 Weather Conditions, Could Weather Event, Cold Weather Warning, Effective
9 Temperature, Effective Heating Degree Days and Seven-Day Forecast. These
10 defined terms are obsolete now that special rules that used to govern operations
11 during cold weather conditions have been eliminated as part of the recent changes
12 to the timing of the day-ahead market schedule that the Commission accepted in
13 Docket No. ER13-895 and which were implemented on May 23, 2013.

14

15 **Q: WHERE THERE ANY OTHER CHANGES YOU WANTED TO DISCUSS?**

16

17 A: Yes. There are a number of proposed changes to the tariff language to further
18 clarify existing provisions. These include:

- 19 • In section III.1.10.1A (a), clarifying that Price-sensitive Demand Bids and
20 Decrement Bids must be greater than 0 MW, as a bid at 0MW has no practical
21 purpose in the market.
- 22 • In section III.1.10.1A (d), language pertinent to what costs are not considered
23 on External Transactions was moved to section III.1.10.1A (c) which is
24 specific to External Transactions.

- 1 • In section III.1.10.1A (d), removed unnecessary details related to how Supply
2 Offers are submitted
- 3 • In section III.1.10.1A (e) (i) “or Load Asset” to reflect that a Demand Bid can
4 also come from a Load Asset in the Day-Ahead Energy Market.
- 5 • In Section III.1, lower case references to the newly defined term “Minimum
6 Run Time” were capitalized to properly reference the defined term.
- 7 • In Section III.1, references to the \$1,000/MWh energy offer cap were replaced
8 with the new defined term “Energy Offer Cap.”
- 9 • In Section III.1, references to the \$0.00/MWh offer floor were replaced with
10 the new defined term “Energy Offer Floor.”

11

12 **Q: DOES THIS CONCLUDE YOUR TESTIMONY?**

13

14 **A:** Yes.

15

16

1 I declare, under penalty of perjury, that the foregoing is true and correct.

2 Executed on July 1, 2013.

3

4

5



6 _____
7 Robert G. Ethier
8 Vice President, Market Development

9

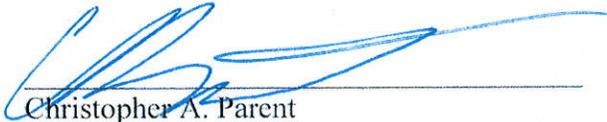
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15 _____
16 Christopher A. Parent
17 Manager, Market Development

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**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

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**ISO New England Inc. and
New England Power Pool**

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Docket No. ER13-____-000

TESTIMONY OF MARIO S. DEPILLIS JR., Ph.D.

Q: PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A: My name is Mario S. DePillis, Jr. I am employed by ISO New England Inc. (the “ISO”) as an Economist with the Internal Market Monitor. My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A: I have a Bachelor of Arts in Philosophy from Carleton College and a Ph.D. in Economics from the University of Texas at Austin. I have more than 17 years experience in the electric energy industry. Prior to 1999 I was employed at the Public Utility Commission of Texas where I was an expert witness on competitive issues and rate cases. Since 1999, I have worked at the ISO in various capacities as Principal Analyst in Market Development, and as part of the Internal Market Monitor as Supervisor of Compliance, Supervisor of Market Assessment, and Economist of Market Assessment and Investigations.

1 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

2

3 A: The purpose of my testimony is to explain the changes to the mitigation rules that are
4 necessary so that they will be consistent with the new energy market offer flexibility rules
5 (the “Offer Flexibility Changes”) that will allow Market Participants to submit offers that
6 vary by hour, change offers in real time and submit offers as low as negative \$150/MWh.

7

8 **Q: HOW IS YOUR TESTIMONY ORGANIZED?**

9

10 A: I will first summarize the six areas in which market rule changes are needed to align the
11 market monitoring and mitigation rules in Appendix A to the Offer Flexibility Changes
12 and the reasons the conforming changes are needed. Then I will explain each of the
13 Appendix A changes in turn.

14

15 **SUMMARY OF CHANGES**

16

17 **Q: PLEASE DESCRIBE THE MITIGATION AND CONSULTATION CHANGES**
18 **THAT ARE NECESSARY TO SUPPORT THE IMPLEMENTATION OF THE**
19 **NEW ENERGY MARKET OFFER FLEXIBILITY RULES.**

20

21 A: Currently a Market Participant makes only one offer for all 24 hours of the Operating
22 Day, whether in the Day-Ahead Energy Market or during the Re-Offer Period. With a
23 few exceptions related to physical operating characteristics, the offer is fixed for all 24
24 hours and cannot be changed in real time. The Internal Market Monitor (“IMM”)
25 calculates a corresponding fixed Reference Level, which is an estimate of a resource’s
26 economic cost of providing energy. The Reference Level is used to evaluate the offer for
27 potential mitigation.

28

1 Under the Offer Flexibility Changes, Market Participants may submit offers that vary by
2 hour and can change offers in real time. The ability to submit offers that vary by hour
3 and that can be changed in real time recognizes that fuel prices and other costs may
4 change over the hours of the day and in real time. The Appendix A changes will align
5 the mitigation rules with the Offer Flexibility Changes.

6
7 There are six areas in which Appendix A will be aligned with the Offer Flexibility
8 Changes:

- 9 1. The use of hourly Reference Levels rather than Reference Levels that are fixed for an
10 Operating Day. The hourly Reference Levels will incorporate fuel price information
11 from Market Participants.
- 12 2. Flexible duration of mitigation rather than mitigation that is fixed for an Operating
13 Day.
- 14 3. Changes to the calculation of cost recovery that is allowed if a Supply Offer is
15 mitigated to a level that is below a resource's costs so that the calculation is limited to
16 the period during which mitigation occurred rather than applying for the entire
17 Operating Day.
- 18 4. Revision of the local reliability commitment mitigation threshold to use only the 10%
19 of low load cost threshold and not the \$80/MW threshold as well.
- 20 5. The introduction of limits to the amount that Start-Up Fees and No-Load Fees may be
21 increased in real time based on real-time fuel price information.
- 22 6. The evaluation of dual fuel resources based on the fuel selected by the Market
23 Participant in its Supply Offer.

1

2 **Q: WHAT IS THE REASON FOR MAKING REFERENCE LEVELS HOURLY?**

3

4 A: Hourly Reference Levels will match up with Market Participants' new ability to submit
5 Supply Offers that vary by hour. The hourly Reference Levels will reflect the same
6 updates to fuel and other cost information that will underlie the Market Participant's
7 hourly Supply Offers. Thus, if the market price for gas increases during the day, the
8 Reference Level for a particular resource's Supply Offer will also increase.

9

10 **Q: WHAT IS THE REASON FOR CHANGING THE DURATION OF**
11 **MITIGATION?**

12

13 A: Under the current rules the duration of mitigation is aligned with the duration of offers.
14 Since an offer is currently fixed for the Operating Day, the duration of mitigation
15 generally extends to the end of the Operating Day. Under the new rules offers will vary
16 by hour, thus changes are needed to the duration of mitigation in order to recognize that
17 offers can be changed hourly. Most importantly, an offer that violates mitigation tests in
18 one hour may be changed and may not violate mitigation tests in subsequent hours.

19

20 **Q: WHAT IS THE REASON FOR CHANGING THE HOURS USED TO**
21 **CALCULATE THE COST RECOVERY ALLOWED WHEN A RESOURCE IS**
22 **MITIGATED BELOW ITS COST?**

23

24 A: Since the purpose of the cost recovery provisions in Section III.A.15 of Appendix A is to
25 prevent mitigation from inappropriately causing a Market Participant to receive payments
26 that are lower than its costs, the calculation of costs and revenues for this purpose should
27 be determined based on the duration of mitigation. Under the current rules, once

1 mitigation is initiated it continues for the entire Operating Day and it is appropriate for
2 cost recovery to be calculated over the entire day. Under the Offer Flexibility Changes,
3 the period of mitigation may be less than a day and the calculations for purposes of
4 determining cost recovery should be based on the duration of mitigation under the new
5 rules.

6
7 **Q: WHAT IS THE REASON FOR REVISING THE LOCAL RELIABILITY**
8 **COMMITMENT MITIGATION THRESHOLD TO USE ONLY THE 10% OF**
9 **LOW LOAD COST THRESHOLD?**

10
11 **A:** The current threshold evaluates the cost of running a resource at low load. Mitigation
12 occurs if the cost based on offers exceeds either 110% of the cost based on Reference
13 Levels or the difference exceeds \$80/MW. During the most recent winter the level and
14 volatility of natural gas prices made it very difficult for a Market Participant to avoid
15 mitigation even when offering competitively. This was because at high gas prices a
16 Supply Offer would trigger the \$80/MW threshold, but be below the 10% threshold.

17
18 **Q: WHAT IS THE REASON FOR LIMITING INCREASES IN START-UP AND NO-**
19 **LOAD FEES IN REAL-TIME TO CHANGES IN FUEL PRICES DURING REAL-**
20 **TIME?**

21
22 Under the current rules, Start-Up Fees and No-Load Fees cannot be changed in real time.
23 This prevents a Market Participant with a resource that is committed in real time from
24 increasing these fees after being notified of the commitment or, in the case of No-Load
25 Fees, after the resource has come on-line. The Offer Flexibility Changes will allow
26 changes to these fees in real time. Since the real-time dispatch software, in contrast to the
27 commitment software, does not evaluate Start-Up Fees and No-Load Fees, raising these

1 fees after receipt of a start order will not cause a resource to be shut down for economic
2 reasons. Limiting real-time changes to Start-Up Fees and No-Load Fees based on the
3 percentage of real-time changes in fuel prices will prevent strategic bidding that would
4 raise prices inappropriately.

5
6 **Q: WHAT IS THE REASON FOR CHANGING THE MITIGATION RULES**
7 **CONCERNING THE EVALUATION OF DUAL FUEL RESOURCES?**

8
9 **A:** Currently a Market Participant with a dual fuel resource is obligated to submit a Supply
10 Offer that is based on use of the lowest cost fuel unless it notifies the IMM prior to
11 submitting the offer and explains why it must burn the more expensive fuel. The
12 experience of the past winter illustrated that Market Participants need the ability to burn
13 either fuel on a given day to effectively manage their fuel supply. Most of the dual fuel
14 resources in New England use oil as a back-up fuel. However, there are often
15 environmental permits restricting the amount of oil that can be burned to certain
16 situations or to a given quantity over a month or a year. Some Market Participants also
17 may maintain limited oil inventories because oil has been much more expensive than
18 natural gas in recent years. When gas prices spiked this past winter and oil became less
19 expensive, Market Participants had to request permission from the IMM to burn natural
20 gas rather than oil in order to conserve their limited amount of oil. Under the Offer
21 Flexibility Changes, a Market Participant will be able to indicate in its Supply Offer
22 which fuel it intends to burn and References Levels for the resource will be calculated
23 based on that fuel.

1 **HOURLY REFERENCE LEVELS WITH FUEL PRICE INFORMATION**
2 **FROM MARKET PARTICIPANTS**

3
4 **Q: PLEASE SUMMARIZE AGAIN WHY THE INTERNAL MARKET MONITOR**
5 **PROPOSES TO MAKE REFERENCE LEVELS HOURLY?**

6
7 A: The Offer Flexibility Changes are intended to better accommodate changes in fuel prices
8 that can vary by hour and during the Operating Day. The calculation of cost-based
9 Reference Levels uses fuel prices as a primary input and, like competitive offers, should
10 incorporate any variation in fuel prices.

11
12 **Q: WHAT IS THE INTERNAL MARKET MONITOR’S PRIMARY TOOL FOR**
13 **HANDLING FUEL PRICE CHANGES TODAY?**

14
15 A: Under the current rules, the Internal Market Monitor uses the consultation process
16 prescribed in Section III.A.3 of the tariff to determine the competitive fuel cost of a
17 resource.

18
19 **Q: PLEASE DESCRIBE THE CURRENT CONSULTATION PROCESS.**

20
21 A: The consultation process prescribed in Section III.A.3 allows a Market Participant to
22 inform the IMM about their resources’ physical and financial parameters. For example,
23 physical parameters, such as a resource’s heat rate, that change infrequently and may
24 require analysis by the IMM are discussed far enough in advance of the Operating Day
25 that consultation is required to be completed no later than 5:00 p.m. two days before the
26 Operating Day. On the other hand, consultation concerning changes in financial
27 parameters, primarily fuel costs, must be completed no later than 90 minutes after the
28 day-ahead market offer submission deadline and no later than 60 minutes after the offer
29 submission deadline for the Re-Offer Period. Any changes in unit operating

1 characteristics or Reference Levels are entered manually by the IMM.

2
3 **Q: PLEASE DESCRIBE THE PROPOSED CONSULTATION PROCESS.**

4
5 A: The consultation with regard to unit operating characteristics will remain the same.

6 However, both the process and the timing for changes to fuel prices are being changed
7 significantly. Under the revised consultation process, Market Participants will be able to
8 submit an expected fuel price for each resource through a user interface. These new fuel
9 prices will be used by the IMM in calculating the Reference Levels for each resource,
10 provided the prices are accurate and verifiable. These fuel prices can be entered in real
11 time and may vary hourly to reflect changes in the fuel markets. The fuel price
12 information that a Market Participant submits, termed a “fuel price change” or “fuel price
13 adjustment” in the proposed rules, will be filtered to ascertain whether the submitted fuel
14 price is consistent with the IMM’s estimate of prices for that day, hour and pipeline. This
15 filtering process is discussed in more detail below.

16
17 **Q: WHY IS THE COLLECTION OF PRICE INFORMATION FROM MARKET**
18 **PARTICIPANTS BEING AUTOMATED?**

19
20 A: The Offer Flexibility Changes introduce 24 possible offer opportunities in addition to the
21 offers for the Day-Ahead Energy Market and the Re-Offer Period, for a total of 26 offer
22 opportunities. This results in 26 possible consultation periods. With the limited
23 opportunities to change offers under the current rules, it is possible for the IMM to
24 discuss fuel price changes with each Market Participants. However, the enhanced ability
25 to change offers under the Offer Flexibility Changes significantly increases the number of

1 opportunities to make a fuel price adjustment. Under the new rules, it is no longer
2 practical for the IMM to discuss each fuel price change with Market Participants.

3
4 **Q: HOW WILL THE NEW CONSULTATION PROCESS PREVENT THE MISUSE**
5 **OF FUEL PRICE ADJUSTMENTS TO CIRCUMVENT MITIGATION?**

6
7 A: There are three mechanisms that will prevent Market Participants from entering fuel
8 prices to avoid mitigation. First, the IMM will set a limit on the fuel price it will use in
9 calculating a resource's Reference Level based on available fuel price indices and market
10 conditions. Second, if a Market Participant enters a fuel price adjustment and
11 simultaneously enters a new Supply Offer, its new offer must be within 10% of the
12 Reference Level calculated based on the new fuel price. Third, a Market Participant that
13 enters a fuel price adjustment must submit documentation verifying that the submitted
14 fuel price is based on a fuel price quote, contract or price from an electronic trading
15 system. A Market Participant that fails to submit verification will be excluded from
16 submitting a fuel price adjustment for the applicable resource for a period of time. The
17 verification process is discussed in more detail below.

18
19 **Q: HOW WILL MARKET PARTICIPANTS SUBMIT FUEL PRICE CHANGES?**

20
21 A: A Market Participant will be able to submit information about the expected market price
22 for fuel through the same bidding interface it uses to enter Supply Offers. The software
23 will check the submitted fuel price against an upper limit set by the IMM and a fixed
24 lower limit. Fuel prices that fall within these limits will be accepted and used as the basis
25 for establishing the Reference Level used for mitigation purposes.

1

2 **Q: SHOULD THE FUEL PRICE REPRESENT AN INCURRED COST OR AN**
3 **EXPECTED COST?**

4

5 A: An offer to supply electricity at some time in the future (*i.e.*, tomorrow, tonight or an
6 hour from now) should be based on expected fuel costs at the time the electricity will be
7 generated. A Supply Offer that is based on the expected market price for fuel should
8 efficiently allocate fuel between generation resources and alternative purposes.

9

10 **Q: WILL THERE BE ANY LIMITS ON THE FUEL PRICE CHANGES?**

11

12 A: Yes. There will be an upper limit based on current market conditions and a lower limit.

13

14 **Q: WHAT IS THE PURPOSE OF SETTING A MINIMUM LEVEL FOR A FUEL**
15 **PRICE CHANGE?**

16

17 A: The use of a minimum fuel price adjustment is intended to minimize unnecessary
18 documentation and audits. This reduces costs for both Market Participants and the ISO.

19

20 **Q: WHAT IS THE BASIS FOR THE PROPOSED MINIMUM FUEL PRICE**
21 **CHANGE LEVEL?**

22

23 A: The existing conduct tests include a margin of error or threshold to reflect the fact that a
24 Reference Level is an estimate of a resource's cost and, like any estimate, is subject to
25 measurement error. The two main sources of measurement error are fuel prices and
26 changes in unit operating characteristics. The proposed minimum fuel price change is the
27 lower of 10% of the fuel price used to calculate the Reference Level or \$2.50/MMBtu. If
28 a Market Participant's offer is based on fuel prices within this threshold, it will not be

1 mitigated and, consequently, there is no need to enter a fuel price adjustment. The
2 thresholds are derived from the tightest mitigation thresholds in Appendix A. The 10%
3 threshold is prescribed by the Local Reliability Commitment Mitigation Conduct Test
4 specified in Section III.A.5.5.5.2. The \$2.50/MMBtu threshold corresponds to the
5 Constrained Area Energy Mitigation Conduct Test specified in Section III.A.5.5.2.2,
6 which includes a \$25/MWh threshold, converted to fuel price for a resource with a
7 10,000 Btu/kWh heat rate. Under normal conditions the tightest mitigation threshold is
8 10%. When fuel prices are very high or a resource is highly inefficient, the \$25/MWh
9 threshold can be triggered first.

10
11 **Q: WHAT IS THE PURPOSE OF THE MAXIMUM FUEL PRICE ADJUSTMENT?**

12
13 A: As discussed later in the testimony, the Appendix A changes include several controls on
14 the use of the participant-submitted fuel price facility, but these are after-the-fact
15 mechanisms. Without a maximum level, a participant with market power might use the
16 consultation process to enter a very high expected fuel price and potentially set a high,
17 non-competitive, energy price in the market. Once the market has cleared, it is not
18 feasible to retroactively correct the market outcomes that were influenced by the
19 inappropriately high Supply Offer.

20
21 **Q: HOW WILL THE INTERNAL MARKET MONITOR DETERMINE THE**
22 **MAXIMUM FUEL PRICE?**

23
24 A: The IMM will consider both fuel market and delivery conditions that affect fuel prices to
25 estimate an upper bound on fuel price changes. The information that the IMM will

1 consider will include:

- 2 • Market Participant-reported quotes for trading and fuel costs;
- 3 • The spread between bids and asks for current fuel delivery;
- 4 • Fuel trading volumes;
- 5 • Near-term price quotes for fuel such as the remainder of the week;
- 6 • Expected natural gas heating demand;
- 7 • Current and forecasted fuel delivery constraints; and
- 8 • Current line pack levels for natural gas pipelines.

9
10 **Q: HOW WILL THE INTERNAL MARKET MONITOR CALCULATE**
11 **REFERENCE LEVELS IF A MARKET PARTICIPANT REQUESTS A FUEL**
12 **PRICE ADJUSTMENT THAT EXCEEDS THE PRICE CALCULATED BY THE**
13 **IMM?**

14
15 A: In this case the Reference Level will be calculated based on the maximum fuel price
16 calculated by the IMM. However, the IMM will record the requested fuel price both for
17 purposes of analysis of current market trends and for use in any cost recovery filing
18 submitted pursuant to Section III.A.15.

19
20 **Q: CAN A MARKET PARTICIPANT SUBMIT A SUPPLY OFFER AT A LEVEL**
21 **EXCEEDING THE MAXIMUM LEVEL SET BY THE IMM?**

22
23 A: Yes. The expected fuel price entered by the Market Participant will not limit the level of
24 the Supply Offer that may be submitted. Mitigation will not result unless the Supply
25 Offer violates both the conduct and the impact tests specified in Section III.A.5.5. If
26 mitigation does occur and the Market Participant can show that its actual costs exceeded
27 the mitigated Supply Offer, then the Market Participant is entitled to seek recovery of

1 actual costs pursuant to Section III.A.15.

2
3 **Q: WHEN CAN MARKET PARTICIPANTS CONSULT WITH THE INTERNAL**
4 **MARKET MONITOR REGARDING FUEL PRICE ADJUSTMENTS AND**
5 **OTHER FACTORS THAT MAY IMPACT REFERENCE LEVELS?**
6

7 A: Market Participants will be able to consult the IMM from 8:00 a.m. to 5:00 p.m. every
8 day. Unlike the current consultation process that focuses on individual fuel costs, the
9 new consultation process will focus on expected market fuel prices. The IMM will use
10 the results of the consultation process to adjust the maximum market price set by the
11 IMM in the fuel price submission software for all affected generators, for example, all
12 generators on a single pipeline.

13
14 **Q: HOW ARE THE RULES DESIGNED TO PREVENT A MARKET PARTICIPANT**
15 **FROM USING THE CONSULTATION PROCESS AS A WAY TO AVOID**
16 **MITIGATION AND EXERCISE MARKET POWER?**
17

18 A: The rules are designed to prevent attempts by Market Participants to exercise market
19 power by avoiding mitigation by submitting expected prices that are not supportable.
20 The potential for abuse arises because the rules allow Market Participants to submit
21 expected market fuel prices in advance, albeit limited by the IMM's estimate of a
22 reasonable zone of prices given current conditions. The remaining potential for abuse is
23 addressed through two *ex post* verification tests. The first test compares the expected fuel
24 price submitted by the Market Participant to the associated Supply Offer. They should be
25 closely aligned. The second test requires documentation, such as a named trader quote,
26 to substantiate the expected fuel price.

1 **Q: PLEASE DESCRIBE THE FIRST TEST.**

2

3 A: Supply Offers may be no greater or less than 10% above or below the Reference Level
4 calculated with the submitted fuel price.

5

6 **Q: HOW DOES THE SUPPLY OFFER TEST HELP PREVENT MISUSE OF**
7 **PARTICIPANT-SUBMITTED FUEL PRICES?**

8

9 A: As noted above, one of the main sources of error in estimating a resource's Reference
10 Level is fuel price uncertainty. If a Market Participant submits its own fuel price, then
11 that source of error is eliminated. In this context, requiring that offers be within 10% of
12 the Reference Level makes sense. This prevents a Market Participant from "double
13 dipping," *i.e.* submitting a fuel price adjustment that results in a higher Reference Level
14 and then having the full measurement error threshold applied on top of that.

15

16 **Q: PLEASE DESCRIBE THE SECOND TEST.**

17

18 A: The second test requires documentation to support the submitted fuel price.

19

20 **Q: HOW DOES THE SECOND SUPPLY OFFER TEST HELP PREVENT MISUSE**
21 **OF SUBMITTED FUEL PRICES?**

22

23 A: The documentation requirement allows the IMM to verify that an expected fuel price
24 submitted by a Market Participant that is used to determine the Reference Level for
25 mitigation was consistent with, or can be linked to, evidence of an expected market price.
26 The evidence may be in the form of a quote, an invoice or documentation that a
27 previously agreed upon methodology was followed to derive the expected market price.
28 A failure to provide documentation that allows the IMM to derive a fuel price similar to

1 that requested by the Market Participant will lead to temporary loss of the ability to
2 submit fuel price changes for the specific resource, which in turn exposes the Market
3 Participant to increased risk. The temporary suspension of the right to submit fuel price
4 changes is described in more detail later in the testimony.

5
6 **Q: WHAT TYPE OF DOCUMENTATION IS THE MARKET PARTICIPANT**
7 **EXPECTED TO PROVIDE?**

8
9 A: The second test requires documentation to support submitted fuel price. Documentation
10 includes but is not limited to quotes from named suppliers, invoices, or a price from a
11 public trading platform. In addition, the Market Participant is required to provide
12 evidence that a transaction involving an affiliated gas trading entity is similar to an arm's
13 length transaction.

14
15 **Q: CAN A SUPPLY OFFER BE BASED ON A FUEL PRICE THAT IS DIFFERENT**
16 **THAN THE QUOTE FROM A NAMED SUPPLIER OR THE PRICE FROM A**
17 **PUBLICLY AVAILABLE TRADING PLATFORM OR PRICE REPORTING**
18 **AGENCY?**

19
20 A: Yes. A Market Participant can request a value to be added to the quote or price that
21 reflects their expected fuel cost. However, the "adder" value or the methodology the
22 Market Participant will use to determine the adder must be submitted and approved by
23 the IMM in advance using the consultation process described in Section III.A.3.

1 **Q: WHY WOULD A MARKET PARTICIPANT NEED TO APPLY AN ADDER TO**
2 **A QUOTE FROM A NAMED SUPPLIER OR A PRICE FROM A PUBLICLY**
3 **AVAILABLE TRADING PLATFORM OR PRICE REPORTING AGENCY?**
4

5 A: One reason a Market Participant may need to apply an adder is that the quote they
6 received from a supplier was for a different time period than the period for which they are
7 submitting a Supply Offer. For example, a Market Participant may have received a quote
8 from a gas supplier in the morning and later in the day the Market Participant may wish
9 to update its Supply Offer for the afternoon. If the Market Participant does not have an
10 updated quote from the gas supplier it could instead include an adder in its Supply Offer
11 that reflects the volatility observed in the intra-day gas market on the publically trading
12 platforms.

13
14 Another reason a Market Participant may need to apply an adder is to reflect different
15 natural gas purchase quantities. A Market Participant may be able to receive a quote or
16 observe pricing on a publically trading platform for a smaller quantity of natural gas than
17 the Market Participant expects to need. If the Market Participant does not have an
18 updated quote from a gas supplier, or is not able to obtain quotes or observer pricing for
19 the quantity of gas it needs to purchase, the Market Participant may include an adder that
20 reflects the difference in quoted or traded volume versus the volume that was expected to
21 be purchased.

22
23 **Q: DOES THE ADDER NEED TO BE A FIXED VALUE?**
24

25 A: There will be one fixed adder value for each submitted fuel price. However, the fixed
26 value can be determined using a methodology or formula or percentage proposed, in

1 advance, by the Market Participant pursuant to the consultation process. Thus, the adder
2 may be a different value for each submitted fuel price depending on the Market
3 Participant's proposed methodology, formula or percentage and, in the case of a
4 methodology or formula, the inputs thereto.

5
6 **Q: WHAT ARE THE CONSEQUENCES TO THE MARKET PARTICIPANT IF IT**
7 **FAILS EITHER TEST?**

8
9 A: If within a 12 month period a Market Participant fails either test for a particular resource,
10 then that specific resource's Reference Levels will be calculated using the default publicly
11 available fuel price indices. The software will not accept participant-submitted fuel
12 prices. Upon the first failure, the exclusion period is two months. Upon the second
13 failure, the exclusion period is six months.

14
15 **Q: WHY IS THE INTERNAL MARKET MONITOR PROPOSING A GRADUATED**
16 **EXCLUSION PROVISION?**

17
18 A: The IMM has designed a flexible Reference Level calculation method that trusts the
19 expected price information submitted by Market Participants provided that they allow the
20 IMM to verify the facts and assumptions underlying the expected prices. Failure of the
21 verification tests means that the fuel price submitted by the Market Participant cannot be
22 trusted. Exaggerated Reference Levels have the potential to affect the clearing prices in
23 the energy market. This potential damage to the rest of the market requires immediate
24 action to exclude any further potential damage. The periods of two and six months
25 correspond to a similar exclusion used in the New York market for participant-submitted
26 fuel prices.

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Q: WHY IS THE INTERNAL MARKET MONITOR PROPOSING TO MODIFY THE COMMITMENT COST THRESHOLD FOR THE LOCAL RELIABILITY COMMITMENT MITIGATION?

A: The original design included both a 10% threshold and a threshold based on a total dollar amount of \$80/MW. Historically the \$80/MW threshold has only triggered when the fuel price is expensive, typically oil, and the cost of running the resource at minimum is high compared to its total capacity. These can be described as expensive and inflexible oil-fired resources. Since the oil price has been much less volatile than gas, it was not anticipated that a Market Participant would have difficulty bidding competitively and staying within the \$80/MW threshold when it was less than the 10% threshold.

During the most recent winter, however, gas prices rose to levels that were higher than oil during certain periods. At the same time gas prices were very volatile. This led to the mitigation of gas-fired generators because of the \$80/MW threshold. Given the volatility at the time, it would have been difficult for Market Participants to avoid violating the conduct test while submitting offers based on widely varying natural gas prices.

DURATION OF MITIGATION

Q: WHAT IS THE PROPOSED DURATION OF MITIGATION?

A: For the Day-Ahead Energy Market, the proposed duration of mitigation in Section III.A.5.6 is limited to the hour in which the Supply Offer has violated both the conduct and impact tests. For the Real-Time Energy Market, the proposed duration of mitigation also begins in the hour in which a Supply offer violates both the conduct and impact tests,

1 but continues until the market power condition, *i.e.*, pivotal supplier status or constrained
2 area status, no longer exists for at least one hour.

3
4 The beginning of commitment mitigation remains unchanged; it is the first hour a
5 resource is kept on-line by the ISO or at the time of the decision to commit the resource.
6 Commitment mitigation continues to the end of the resource's minimum run time. In the
7 case of local reliability commitment mitigation, the duration of mitigation will extend
8 beyond the minimum run time if the reliability need extends beyond the minimum run
9 time.

10
11 **Q: WHY IS THE IMM PROPOSING TO MODIFY THE DURATION OF**
12 **MITIGATION FOR RESOURCES SUBJECTED TO ENERGY OR**
13 **COMMITMENT MITIGATION?**

14
15 A: Under the current rules a Market Participant that has failed the conduct test has no
16 opportunity to change its offer to be competitive until its offer for next operating day is
17 accepted. The current mitigation rules reflect this by extending the duration of mitigation
18 to the longer of the Operating Day or the resource's minimum run time.

19
20 Under the proposed rules, a Market Participant with an offer that fails a conduct test in
21 the real-time market has the opportunity to change the offer for future hours. In the day-
22 ahead market the Market Participant can submit different offers for each hour, some of
23 which may fail the conduct test and some of which may not.

24
25 The new duration rules align the duration of mitigation with the ability to submit offers

1 that vary by hour.

2
3 **Q: WHY IS THE IMM PROPOSING TO EXTEND THE DURATION OF**
4 **MITIGATION IN REAL TIME UNTIL A MARKET PARTICIPANT'S**
5 **RESOURCE FACES A STRUCTURALLY COMPETITIVE MARKET?**
6

7 A: When a Market Participant's Supply Offer is mitigated, the IMM automatically sends the
8 Market Participant an email stating that the offer has been mitigated and the reason why.
9 By revealing, for example, that the offer violated the pivotal supplier test the automatic
10 notice provides information that is not available to other Market Participants. With the
11 ability to change offers in real time on an hourly basis, this information can be used
12 strategically by the Market Participant, either by making its offers less competitive or by
13 not lowering existing non-competitive offers. This strategy would not be available
14 currently because offers may not be changed after the Re-Offer Period. To remedy this
15 concern, the Appendix A changes provide that mitigation continues until the area where a
16 resource is located has been shown to be competitive, *i.e.* until the resource is not pivotal
17 and is not in a constrained area for at least one hour.

18
19 **CALCULATION OF ADDITIONAL COST RECOVERY WHEN A RESOURCE**
20 **DOES NOT RECOVER ITS FULL COSTS FOLLOWING MITIGATION**
21

22 **Q: UNDER THE PROVISION THAT PERMITS A MARKET PARTICIPANT TO**
23 **REQUEST ADDITIONAL COST RECOVERY WHEN ITS SUPPLY OFFER IS**
24 **MITIGATED AND IT DOES NOT FULLY RECOVER ITS COSTS, WHY IS THE**
25 **LENGTH OF TIME OVER WHICH A MARKET PARTICIPANT'S**
26 **COMPENSATION IS CALCULATED BEING CHANGED?**
27

28 A: In some cases, a Market Participant may not be able to recover the fuel and variable
29 operating and maintenance costs for its resource despite the fact that the IMM has

1 correctly applied the mitigation rules. In these cases, a Market Participant is entitled to
2 submit a filing to the Commission to seek recovery of its costs. Under the current rules,
3 the revenues and costs associated with a resource that is requesting additional cost
4 recovery following mitigation are calculated over the entire Operating Day. This is
5 aligned with the current offer structure and the application of mitigation to Supply Offers
6 from the start of mitigation to the end of the Operating Day. Under the Offer Flexibility
7 Changes, offers may vary by hour and mitigation may occur for some hours but not
8 others. Therefore, the Appendix A changes revises the cost recovery provision so that the
9 cost recovery calculation is based on the revenues and costs for the duration of any period
10 of mitigation rather than for the remainder of the Operating Day.

11
12 **LIMITS TO REAL-TIME INCREASES IN START-UP FEES AND NO-LOAD**
13 **FEES**

14
15 **Q: WHY IS THE AMOUNT THAT A MARKET PARTICIPANT CAN INCREASE A**
16 **RESOURCE'S START-UP FEES AND NO-LOAD FEES IN REAL TIME**
17 **LIMITED TO A PERCENTAGE INCREASE BASED ON THE FUEL PRICE**
18 **SUBMITTED BY THE MARKET PARTICIPANT?**

19
20 **A:** The Offer Flexibility Changes provide the opportunity for a Market Participant to change
21 a Supply Offer for a resource after the resource has been scheduled. Increases in
22 incremental energy offers can be sufficiently monitored and, if necessary, mitigated in
23 these circumstances. Start-Up Fee and No-Load Fees, however, are only mitigated at the
24 time of commitment. This creates the possibility that a Market Participant, once issued a
25 start-up notification, could modify these fees without being subject to any review or
26 mitigation. This strategy is infeasible today because offers may not be changed in real
27 time. The Appendix A changes limit increases in Start-Up Fees and No-Load Fees as

1 follows: (1) if a fuel price adjustment has been submitted, then the increase is limited to
2 the percent increase in the new fuel price, relative to the fuel price otherwise used by the
3 IMM, and; (2) if no fuel price adjustment has been submitted, then the limit is the Start-
4 Up Fee and No-Load Fee values submitted in the Re-Offer Period. Fuel is the only
5 component of Start-Up Fees and No-Load Fees that should change during the Operating
6 Day.

8 **EVALUATION OF DUAL FUEL RESOURCES**

9
10 **Q: HOW DO THE CURRENT RULES REQUIRE THE IMM TO EVALUATE**
11 **SUPPLY OFFERS FOR DUAL FUEL RESOURCES?**

12
13 A: The current market rules require that the IMM evaluate a Supply Offer based on the
14 lower cost fuel by default, unless a Market Participant requests an evaluation based on
15 the higher cost fuel. The request is granted if the Market Participant reports that the
16 higher cost fuel is necessary for the continued availability of the resource. The Market
17 Participant is required to provide the IMM with: (1) documentation of the cause for the
18 use of the higher cost fuel, and; (2) evidence that the resource actually burned the higher
19 cost fuel or did not run.

20
21 **Q: WHY IS THE REQUIREMENT THAT MARKET PARTICIPANTS WITH DUAL**
22 **FUEL RESOURCES SUBMIT SUPPLY OFFERS BASED ON THE RESOURCE'S**
23 **LEAST COST FUEL BEING ELIMINATED?**

24
25 A: During the past winter the IMM observed that Market Participants with several dual fuel
26 resources did not perform in accordance with their Supply Offers because the Market
27 Participants were either unable or unwilling to procure natural gas. Market Participants

1 with dual fuel resources can manage the delivery and price risk associated with natural
2 gas by offering based on oil costs and can conserve oil by offering on natural gas.
3 Eliminating the requirement to submit an offer based on the least cost fuel gives Market
4 Participants more flexibility to assure the availability of the dual fuel resource. In order
5 to provide this greater flexibility to ensure the availability of dual fuel resources, the
6 Appendix A changes remove the requirement that the Supply Offer be evaluated by
7 default on the basis of the less expensive fuel. The IMM will continue to collect
8 documentation on the fuel used and the reasons for offering based on the more expensive
9 fuel. The IMM will in particular look for instances in which a Market Participant may
10 have been able to raise prices by submitting an offer based on the more expensive fuel.
11 In such cases the documentation provided by the Market Participant will receive careful
12 scrutiny and may result in referral to the Commission if found to be inadequate.
13

1 Q: DOES THIS CONCLUDE YOUR TESTIMONY?

2 A: Yes.

3

4 I declare under penalty of perjury that the foregoing is true and correct.

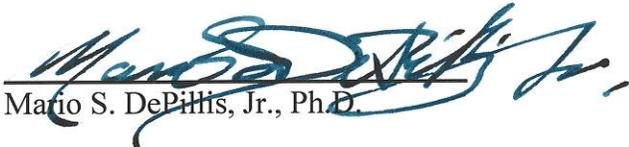
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6 Executed on June 28, 2013

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