



June 14, 2019

**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, Market Rule 1 Revisions to the Offer Cap Requirements in the Day-Ahead Energy Market and Change to Effective Date for Order No. 831 Revisions; Docket No. ER19-000**

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act (“Section 205”),<sup>1</sup> ISO New England Inc. (the “ISO”), joined by the New England Power Pool (“NEPOOL”) Participants Committee<sup>2</sup> (together, the “Filing Parties”),<sup>3</sup> hereby submit this transmittal letter and revised Tariff section to revise the dispatch treatment of resources whose Supply Offers are price-capped in the Day-Ahead Energy Market (the “DA Offer Cap Revision”). With this filing, the ISO is also proposing to move the effective date for all of the ISO’s Tariff revisions accepted by the Commission for compliance with Order No.

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<sup>1</sup> 16 U.S.C. § 824d (2012).

<sup>2</sup> 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.

<sup>3</sup> 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, unanimously supported the changes reflected in this filing and, accordingly, joins in this Section 205 filing.

831 from October 1, 2019 to March 1, 2020 (the “Order 831 Offer Cap Revisions”).<sup>4</sup> Therefore, all the revisions to the Tariff accepted by the Commission for compliance with Order No. 831 are re-submitted with this filing with the new March 1, 2020 effective date. The ISO also submits herewith the supporting testimony of Benjamin Ewing (the “Ewing Testimony”),<sup>5</sup> which is sponsored solely by the ISO.

**I. REQUESTED EFFECTIVE DATE FOR DA OFFER CAP REVISION;  
CHANGE TO EFFECTIVE DATE FOR ALL ORDER 831 OFFER CAP  
REVISIONS; REQUESTED ORDER WITHIN 60 DAYS**

**In order to implement the Order 831 Offer Cap Revisions and the DA Offer Cap Revision by the March 1, 2020 effective date requested herein, the ISO respectfully requests that the Commission issue an order within 60 days of the date of this filing.**

In its Order 831 Compliance Filing, the ISO requested an effective date for the Order 831 Offer Cap Revisions of October 1, 2019. As the ISO explained in that filing, the requested effective date was aggressive and assumed that each phase of the implementation went smoothly and was not delayed due to demand from competing priorities. The ISO described in that filing the complexity of the project and the resulting implementation timeline.<sup>6</sup>

The ISO has made significant progress in developing the necessary software and process changes to implement the Order 831 Offer Cap Revisions. However, it is requesting a five-month delay, until March 1, 2020, to complete the implementation. As the ISO explained in its Order 831 Compliance Filing, implementation work for the Order 831 Offer Cap Revisions was to begin in early 2018 after completion of a set of changes to permit storage-related devices to participate in the Energy Market. The design work for the Order 831 Offer Cap Revisions required the knowledge and expertise of the ISO staff tasked with supporting energy storage-related work, and therefore the design work for the Order 831 Offer Cap Revisions could not begin in earnest until the design work on the storage project was complete.<sup>7</sup> However, work on the storage project was delayed due to continued work to implement the ISO’s price-responsive demand rules, which went into effect in June of 2018. Together work on these projects delayed the start of the design work to support the implementation of the Order 831 Offer Cap Revisions.

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<sup>4</sup> See *ISO New England Inc. and New England Power Pool*, Market Rule 1 Revisions to Modify Energy Market Offer Caps in Compliance with Order No. 831, Docket No. ER17-1565-000 (filed May 8, 2017) (the “Order 831 Compliance Filing”); Letter Order Accepting Tariff Revision to Modify Energy Market Offer Caps in Compliance with Order No. 831, Docket No. ER17-1565-000 (issued November 9, 2017).

<sup>5</sup> Mr. Ewing is a Lead Analyst in the ISO’s Market Development Department.

<sup>6</sup> Order 831 Compliance Filing, transmittal letter at pp. 2-4.

<sup>7</sup> *Id.*

The ISO anticipates completing the design and software revisions in time for a March 1, 2020 effective date,<sup>8</sup> and is therefore requesting that the effective date for the Order 831 Revisions be moved from October 1, 2019 to March 1, 2020. The ISO also requests that the DA Offer Cap Revision filed herewith become effective on March 1, 2020.

The March 1, 2020 requested effective date is premised on the assumption that the Commission accepts the DA Offer Cap Revision. By making this additional revision, the ISO will be able to implement the Order 831 Offer Cap Revisions earlier than it otherwise could given the delays it has faced to date and given the complexity that can be avoided by making the DA Offer Cap Revision.

## **II. DESCRIPTION OF THE FILING PARTIES; COMMUNICATIONS**

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

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 500 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,<sup>9</sup> the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, “NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff.”

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<sup>8</sup> At this time, work by the ISO’s software vendor has been completed, and currently the ISO is integrating the revised software into its internal systems. Once this work is complete, rigorous software testing must take place.

<sup>9</sup> *ISO New England Inc., et al.*, 109 FERC ¶ 61,147 (2004).

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

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### III. STANDARD OF REVIEW

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

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<sup>10</sup> 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.

<sup>11</sup> *Atlantic City Elec. Co. v. FERC*, 295 F. 3d 1, 9 (D.C. Cir. 2002).

<sup>12</sup> *Id.* at 10 (quoting *City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

<sup>13</sup> *Id.* at 9.

<sup>14</sup> *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

accurate.”<sup>15</sup> 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.<sup>16</sup>

#### **IV. DISCUSSION OF REVISION TO DAY-AHEAD CAPPING RULE**

##### **A. Background**

Order No. 831 required that all RTOs/ISOs implement the following offer cap structure:

A resource’s incremental energy offer must be capped at the higher of \$1,000/MWh or that resource’s cost-based incremental energy offer. For the purpose of calculating Locational Marginal Prices, Regional Transmission Organizations and Independent System Operators must cap cost-based incremental energy offers at \$2,000/MWh.<sup>17</sup>

This provision contemplates separate treatment for offers up to \$1,000/MWh, offers between \$1,000/MWh and \$2,000/MWh, and offers above \$2,000/MWh.

To comply with the Order No. 831 offer cap requirements, the ISO modified its market rules to add a new Section III.1.9 that addresses the offer capping and cost verification requirements for all energy market offers with incremental energy costs above \$1,000/MWh. To implement the \$2,000/MWh cap required under Order No. 831 for price calculation purposes, Section III.1.9.1.2(a) specifies that if the incremental energy portion of the offer is above \$2,000/MWh, then it is capped at \$2,000/MWh for purposes of performing the day-ahead market and real-time market pricing calculations in Section III.2 of Market Rule 1.<sup>18</sup>

Of particular importance for the DA Offer Cap Revision, while Order No. 831 capped incremental energy offers at \$2,000/MWh, Order No. 831 also stated that for cost-based incremental energy offers above \$2,000/MWh, “we expect RTOs/ISOs to use such offers to determine merit-order dispatch.”<sup>19</sup> The Commission subsequently clarified that Order No. 831 did not *require* the use of cost-based incremental energy offers above

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<sup>15</sup> *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

<sup>16</sup> *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*)).

<sup>17</sup> Order No. 831 at P 42.

<sup>18</sup> The verification requirement specified in Section III.1.9.1.1 ensures that only the cost-verified incremental energy value of any such offer is used for dispatch and in calculating LMPs.

<sup>19</sup> Order No. 831 at P 42.

\$2,000/MWh in determining merit-order dispatch, but rather was only encouraging such treatment to the extent possible.<sup>20</sup>

The Order 831 Offer Cap Revisions apply the \$2,000/MWh cap to cost-verified incremental energy offers only for purposes of pricing. The revisions specifically did not cap cost-verified incremental energy offers for commitment or dispatch purposes. Therefore, under the rules as accepted by the Commission, cost-verified incremental energy offers above \$2,000/MWh are to be used in determining economic merit-order commitment and dispatch decisions in both the Day-Ahead Energy Market and the Real-Time Energy Market.<sup>21</sup>

### **B. Revision to Day-Ahead Capping Rule**

As the ISO has worked through the implementation of the Order 831 Offer Cap Revisions, it has determined that implementing cost-verified incremental energy offers above \$2,000/MWh in the dispatch software in the Day-Ahead Energy Market is significantly more complex than it originally anticipated and would result in a further delay in the implementation of the Order 831 Offer Cap Revisions.<sup>22</sup> Rather than delay the implementation further—and because the Commission expressly has not required the use of cost-verified offers above \$2,000/MWh for dispatch purposes—the ISO is now amending its Order 831 Offer Cap Revisions to clarify that verified offers greater than \$2,000/MWh will be capped at \$2,000/MWh for use in determining the Day-Ahead Energy Market dispatch quantities, as well as for Day-Ahead price calculations.

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<sup>20</sup> Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order on Rehearing and Clarification, 161 FERC ¶ 61,156 (2017) at P 16 (“[W]e clarify that Order No. 831 did not require cost-based incremental energy offers above \$2,000/MWh to be used to determine economic merit-order dispatch. We recognize that some RTO’s/ISO’s existing commitment, dispatch, and pricing algorithms are structured differently, and the Commission in Order No. 831 did not require RTOs/ISOs to change their current practices or software to use cost-based incremental energy offers above \$2,000/MWh for determining economic merit-order dispatch. However, in the event that RTOs/ISOs must select from several offers above \$2,000/MWh, we encourage RTOs/ISOs to make those selections on a least-cost basis when possible, in order to minimize the cost to serve load.”).

<sup>21</sup> See ISO Order No. 831 Compliance Filing, Tariff revisions at Section III.1.9.1.2(a), which states “For purposes of the price calculations described in Section III.2, the incremental energy value of an offer is capped at \$2,000/MWh.” Section III.2 of Market Rule 1 addresses the calculation of Locational Marginal Prices in the Day-Ahead Energy Market and Real-Time Energy Market. The cost-verification rules in Section III.1.9.1.1 ensure that only cost-verified incremental energy offers would be utilized for any offers above \$1,000/MWh, and thus only cost-verified incremental energy offers above \$2,000/MWh would be utilized for commitment and dispatch purposes.

<sup>22</sup> See Ewing Testimony at pp. 7-9 for a discussion of the complexity involved with modifying the pricing and dispatch software to permit the use of cost-verified offers above \$2,000/MWh for dispatch purposes.

The DA Offer Cap Revision to Section III.1.9.1.2 of the capping rules states that for purposes of scheduling a resource that has been committed in the Day-Ahead Energy Market under the scheduling rule in Section III.1.7.6 of Market Rule 1, the incremental energy offer value of the Supply Offer will be capped at \$2,000/MWh. It is important to note that in this context “scheduling” under Section III.1.7.6 refers to the determination of what MWh level the resource will be dispatched to *once the decision to commit the resource is made*. In other words, in the Day-Ahead Energy Market clearing process, cost-verified offers above \$2,000/MWh *will* be used in determining which resources to *commit and bring online*. But in determining how much energy to obtain from those resources (above the resource’s Economic Minimum Limit), which is commonly referred to as “dispatching” the resource above its Economic Minimum Limit, offers will be capped at \$2,000/MWh.

To provide a simplified example of how the capping will work once the DA Offer Cap Revision is implemented, suppose Resources A, B and C are being evaluated for clearing in the Day-Ahead Energy Market. These resources offer a single price for their full capability, and are identical except for their verified offer price.

	Economic Minimum Limit (MW)	Economic Maximum Limit (MW)	Verified Offer Price (\$/MWh)
Resource A	10	20	\$2,100
Resource B	10	20	\$2,200
Resource C	10	20	\$2,300

Suppose that 15 MWh of demand remain to be satisfied in the Day-Ahead Energy Market, and these three resources are the only ones remaining in the supply stack. The Day-Ahead commitment process will consider the uncapped, verified offer of each resource when deciding how to meet demand. As a result, it will choose to commit the less expensive Resource A and leave the more expensive Resources B and C offline. This is an efficient outcome.<sup>23</sup>

Now, suppose instead that 30 MWh of demand remain to be satisfied. The Day-Ahead commitment process would commit Resources A and B, again selecting the lowest cost resources available to satisfy demand. The Day-Ahead dispatch and pricing process, however, would treat each of these committed resources as a \$2,000/MWh resource by application of the hard cap of \$2,000/MWh. As a result of the application of this cap to dispatch as well as to pricing, Resources A and B would be dispatched pro-rata at 15 MW each.<sup>24</sup>

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<sup>23</sup> Ewing Testimony at pp. 6-7.

<sup>24</sup> *Id.*

The ISO evaluated whether to simply delay the implementation of this aspect of the Order 831 Offer Cap Revisions, rather than remove it altogether, but, as explained in the Ewing Testimony, decided against doing so for two reasons. First, the amount of work to create this additional functionality in the Day-Ahead Energy Market clearing is significant. The functionality was developed for the Real-Time Energy Market as part of the ISO's fast start pricing initiative. The software changes for the fast start pricing initiative were some of the more complex changes undertaken by the ISO since the implementation of the current market rules. Much of this same work would need to be performed to "separate" pricing from scheduling (i.e., dispatch) in the Day-Ahead Energy Market.<sup>25</sup> Given that New England has not experienced input fuel prices that would warrant offers close to the \$2,000/MWh offer cap,<sup>26</sup> the ISO cannot justify the expenditure in time or resources that would be required to accomplish this narrow objective. Furthermore, a market clearing software re-platforming is currently being evaluated by both ISO New England and several other ISO/RTOs. While a timeline has not yet been completed for this project, with this re-platforming the future version of the Day-Ahead Energy Market software will inherently include separate dispatch and pricing processes in a manner that will likely allow scheduling to fully utilize the uncapped offers. In short, implementing this change now to the existing Day-Ahead clearing engine would require substantial effort to implement a short-lived change that is unlikely to provide significant value to the marketplace.<sup>27</sup>

## V. STAKEHOLDER PROCESS

The NEPOOL Markets Committee, at its April 9-10, 2019 meeting, voted to recommend that the NEPOOL Participants Committee support the DA Offer Cap Revision, with three abstentions recorded.<sup>28</sup> Following Markets Committee consideration and recommendation of the market rule change, at its May 3, 2019 meeting, the NEPOOL Participants Committee voted unanimously to support the DA Offer Cap Revision, which was included on the Consent Agenda for the meeting.<sup>29</sup>

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<sup>25</sup> See the Ewing Testimony at pp. 7-9 for an explanation of the required work.

<sup>26</sup> With respect, specifically, to supply offers, cost-based Day-Ahead Energy Market supply offers greater than \$2,000/MWh are unlikely. A key driver of Order No. 831 is to allow the marginal costs associated with volatile natural gas prices to be properly reflected in market clearing prices. See Order No. 831 at P 90 (discussing high natural gas prices during the Polar Vortex in the context of establishing the \$2,000/MWh cap). In the last 10 years the highest observed Day-Ahead gas price in New England has been \$107/MMBtu, which is well below a price that would justify a Day-Ahead offer greater than \$2,000/MWh at any heat rate in New England's gas-fired generator fleet. Ewing Testimony at p. 10.

<sup>27</sup> Ewing Testimony at pp. 7-9.

<sup>28</sup> During the April 9 NEPOOL Markets Committee vote, two abstentions were registered in the Generation Sector and one abstention in the Supplier Sector.

<sup>29</sup> The Consent Agenda for a Participants Committee meeting, similar to the Consent Agenda for a Commission open meeting, is a group of actions (each recommended by a Technical Committee



## VI. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the market rule changes do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations.<sup>30</sup> Notwithstanding this 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 and clean Tariff sections reflecting the Order 831 Offer Cap Revisions and the DA Offer Cap Revision submitted in this filing with the new March 1, 2020 effective date;
- Clean Tariff sections effective October 1, 2019 without the Order 831 Offer Cap Revisions;
- Testimony of Benjamin Ewing (the "Ewing 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 I above, the Filing Parties request that the revisions become effective on March 1, 2020.

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/regulatory/ferc/nepool/gov\\_prtcpts\\_eserved.pdf](http://www.iso-ne.com/regulatory/ferc/nepool/gov_prtcpts_eserved.pdf). A copy of this

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(...continued)

or subgroup established by the Participants Committee) to be taken by the Participants Committee through approval of a single motion at a meeting. Although voted as a single motion, all recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. The Participants Committee's unanimous approval of the May 3, 2019 Consent Agenda included its support for the DA Offer Cap Revision.

<sup>30</sup> 18 C.F.R. § 35.13 (2018).

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

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

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

35.13(b)(6) – The ISO's approval of these changes is evidenced by this filing. These changes reflect the results of the Participant Processes required by the Participants Agreement and reflect the unanimous support of the NEPOOL 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 changes herein do not modify a traditional "rate," and the statement required under this Commission regulation is not applicable to the instant filing.

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

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

## **VII. CONCLUSION**

For the reasons explained in this transmittal letter and the supporting testimony, the ISO and NEPOOL request that the Commission accept this filing with the revisions to become effective on March 1, 2020.

The Honorable Kimberly D. Bose  
June 14, 2019  
Page 11 of 11

Respectfully submitted,

**ISO NEW ENGLAND INC.**

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**NEW ENGLAND POWER POOL  
PARTICIPANTS COMMITTEE**

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## **I.2 Rules of Construction; Definitions**

### **I.2.1. Rules of Construction:**

In this Tariff, unless otherwise provided herein:

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

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

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

#### **I.2.2. Definitions:**

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

**Active Demand 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.

**Actual Capacity Provided** is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

**AGC** is automatic generation control.

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

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

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

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

**Alternative Technology Regulation Resource (ATRR)** is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

**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.

**Annual Reconfiguration Transaction** is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

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

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

**Asset** is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

**Asset Registration Process** is the ISO business process for registering an Asset.

**Asset Related Demand** is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration

Process, and is made up of either: (1) 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; (2) a Storage DARD with a consumption capability of at least 0.1 MW; or (3) one or more storage facilities that are not Electric Storage Facilities with an aggregate consumption capability of at least 1 MW.

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

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

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

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

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

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

**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 Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

**Available Energy** is a value that reflects the MWhs of energy available from an Electric Storage Facility for economic dispatch.

**Available Storage** is a value that reflects the MWhs of unused storage available from an Electric Storage Facility for economic dispatch of consumption.

**Average Hourly Load Reduction** is either: (i) the sum of the On-Peak 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; or (ii) the sum of the Seasonal Peak 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. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the 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 On-Peak 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; or (ii) the sum of the Seasonal Peak 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. Electrical energy output and Average Hourly Output shall be determined consistent with the 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.13.7.1.2.2 of Market Rule 1.

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

**Bankruptcy Code** is the United States Bankruptcy Code.

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

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

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

**Binary Storage DARD** is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Binary Storage Facility** is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**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 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 Blackstart O&M calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

**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.

**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 established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

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

**Block** is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

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

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

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

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

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

**Capacity Acquiring Resource** is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

**Capacity Balancing Ratio** is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

**Capacity Base Payment** is the portion of revenue received in the Forward Capacity Market as described in Section III.13.7.1 of Market Rule 1.

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

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

**Capacity 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 as described in Section III.13.7.5.2 of Market Rule 1.

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

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

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

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

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

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

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

**Capacity Performance Bilateral** is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 of Market Rule 1.

**Capacity Performance Payment** is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1.

**Capacity Performance Payment Rate** is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 of Market Rule 1.

**Capacity Performance Score** is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 of Market Rule 1.

**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 Scarcity Condition** is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 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 Transfer Rights (CTRs)** are calculated in accordance with Section III.13.7.5.4.

**Capacity Transferring Resource** is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

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

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

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

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

**Category B Designated Blackstart Resource** has the same meaning as 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 or the demand reduction capability of a Demand Response Resource.

**Cluster Enabling Transmission Upgrade (CETU)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Entry Deadline** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Interconnection System Impact Study (CSIS)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

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

**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 Capacity Commitment Period, 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. 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** is capacity that has achieved FCM Commercial Operation.



**Commission** is the Federal Energy Regulatory Commission.

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

**Common Costs** are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

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

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

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

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

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

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

**Congestion** is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different

from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

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

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

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

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

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

**Continuous Storage ATRR** is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage DARD** is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage Generator Asset** is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage Facility** is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**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.

**Controllable Behind-the-Meter Generation** means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

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

**Coordinated Transaction Scheduling** means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

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

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

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

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

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

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

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

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

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

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

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

**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) of Market Rule 1.

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

**Day-Ahead Demand Reduction Obligation** is defined in Section III.3.2.1(a) of Market Rule 1.

**Day-Ahead Energy Market** means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, 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.

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

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

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

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

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

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

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

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

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

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

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

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

**DDP Dispatchable Resource** is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

**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 Bid Cap is \$2,000/MWh.**

**Demand Capacity Resource** means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

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

**Demand Reduction Offer** is an offer by a Market Participant with a Demand Response Resource to reduce demand.

**Demand Reduction Offer Block-Hours** are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction 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 Demand Reduction 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 Demand Reduction Offer Block-Hours.

**Demand Reduction Threshold Price** is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

**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 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 Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

**Demand Response Asset** is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with Section III.8.1.1.

**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 as determined pursuant to Section III.8.2.



**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 DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

**Demand Response Resource Notification Time** is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts 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 period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

**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, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

**Designated Entity** is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset 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)** means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

**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 Response Resources, change External Transactions, or change the status or consumption of a

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

**Dispatch Zone** means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

**Dispatchable Asset Related Demand (DARD)** is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, 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 Operating Procedures and Manuals.

**Dispatchable Resource** is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

**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 directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that

the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

**DRR Aggregation Zone** is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

**Do Not Exceed (DNE) Dispatchable Generator** is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.1.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

**Do Not Exceed Dispatch Point** is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

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

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

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

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

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

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

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

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

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

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

**Economic Maximum Limit or Economic Max** is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

**Economic Minimum Limit or Economic Min** is (a) for a Generator Asset 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 a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

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

**Effective Offer** is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

**EFT** is electronic funds transfer.

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

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

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

**Electric Storage Facility** is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

**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 output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

**EMS** is energy management system.

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

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

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

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

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

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

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

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

**Energy Non-Zero Spot Market Settlement Hours** are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation 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, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

**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, a Market Participant's share of Zonal Capacity Obligation 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.

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

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

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

**Existing Capacity Resource** is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

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

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

**Existing Demand Capacity Resource** is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

**External Transaction Cap** is \$2,000/MWh for External Transactions other than Coordinated External Transactions and \$1,000/MWh for Coordinated External Transactions.

**External Transaction Floor is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative \$1,000/MWh for Coordinated External Transactions.**

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

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

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

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

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

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

**Fast Start Generator** means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

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

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

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

**FCM Charge Rate** is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

**FCM Commercial Operation** is defined in Section III.13.3.8 of Market Rule 1.

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

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

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

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

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

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

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

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

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

**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.

**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 Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**Forward Reserve Offer Cap** is \$9,000/megawatt-month.

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

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

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

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

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

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

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



**FTR 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 device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset 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 Charges** are defined in Section 1.3 of the ISO New England Billing Policy.

**Hourly PER** is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

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

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

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

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

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

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

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

**Inadvertent Energy Revenue Charges or Credits** is defined in Section III.3.2.1(p) 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 supply at the specified Location in the Day-Ahead Energy Market.

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

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

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

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

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

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

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

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

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

**Interconnection Agreement** is the “Large Generator Interconnection Agreement”, the “Small Generator Interconnection Agreement”, or the “Elective Transmission Upgrade Interconnection Agreement”

pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**ISO** means ISO New England Inc.

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

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

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

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

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

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

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

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

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



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

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

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

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

**ITC Agreement** is defined in Attachment M to the OATT.

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

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

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

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

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

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

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

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

**Limited Energy Resource** means a Generator Asset 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. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

**Load Management** means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage 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, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

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

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

**Local Area Facilities** are defined in the TOA.

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

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

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

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

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

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

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

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

**Local Public Policy Transmission Upgrade** is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System

Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

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

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

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

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

**Local Sourcing Requirement (LSR)** is a value calculated as described in Section III.12.2.1 of Market Rule 1.

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

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

**Location** is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

**Locational Marginal Price (LMP)** is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

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

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

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

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

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

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

**LSE** means load serving entity.

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

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

**Manual Response Rate** is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

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

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

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

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

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

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

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

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

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

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

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

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

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

load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

**Maximum Capacity Limit** is a value calculated as described in Section III.12.2.2 of Market Rule 1.

**Maximum Consumption Limit** is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

**Maximum Daily Energy Limit** is the maximum amount of megawatt-hours that a Limited Energy Resource expects to be able to generate in the next Operating Day.

**Maximum Daily Consumption Limit** is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

**Maximum Facility Load** is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

**Maximum Interruptible Capacity** is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

**Maximum Load** is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

**Maximum Number of Daily Starts** is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.



**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 an On-Peak Demand Resource or Seasonal Peak 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 On-Peak Demand Resources or Seasonal Peak Demand Resources comprised of an aggregation of measures with varied Measure Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the 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 capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the 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 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include 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 an On-Peak Demand Resource or Seasonal Peak Demand Resource 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 On-Peak Demand Resources or Seasonal Peak Demand Resources 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 capability of the On-Peak Demand Resource or Seasonal Peak 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 an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak 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.

**Metered Quantity For Settlement** is defined in Section III.3.2.1.1 of Market Rule 1.

**Minimum Consumption Limit** is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

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

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

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

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

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

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

**Minimum Time Between Reductions** is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

**Minimum Total Reserve Requirement**, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

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

**Monthly Capacity Payment** is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

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

**Monthly PER** is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

**Monthly Real-Time Demand Reduction Obligation** is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWs.

**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 MWhs.

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

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

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

**MUI** is the market user interface.

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

**MW** is megawatt.

**MWh** is megawatt-hour.

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

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

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

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

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

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

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

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

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

**NEPOOL Agreement** is the agreement among the participants in NEPOOL.

**NEPOOL GIS** is the generation information system.

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

**NEPOOL GIS API Fees** are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

**NEPOOL Participant** is a party to the NEPOOL Agreement.

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

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

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

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

**Net Regional Clearing Price** is described in Section III.13.7.5 of Market Rule 1.

**Net Supply** is energy injected into the transmission or distribution system at a Retail Delivery Point.

**Net Supply Capability** is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

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

**Network Customer** is a Transmission Customer receiving RNS or LNS.

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

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

**Network Resource** is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource

located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

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

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

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

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

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

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



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

**New Demand Capacity Resource** is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

**New Demand Capacity Resource Qualification Package** is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

**New Demand Capacity Resource Show of Interest Form** is described in Section III.13.1.4.1.1.1 of Market Rule 1.

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

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

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

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

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

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

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

**NMPTC** means Non-Market Participant Transmission Customer.

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

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

**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 Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset 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 Generator Asset 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.13.7.5.1.3.

**Non-Commercial Capacity** is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

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

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

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

**Non-Dispatchable Resource** is any Resource that does not meet the requirements to be a Dispatchable Resource.

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

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

**Non-Incumbent Transmission Developer** is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. “Non-Incumbent Transmission Developer” also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

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

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

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

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

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

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

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

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

**Northeastern Planning Protocol** is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: [www.iso-ne.com/static-assets/documents/2015/07/northeastern\\_protocol\\_dmeast.doc](http://www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc).

**NPCC** is the Northeast Power Coordinating Council.

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

**Offer Data** means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of 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 or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

**Offered CLAIM30** is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

**On-Peak Demand Resource** is a type of Demand Capacity 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 Generator Asset or a Load Asset, where such facility 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.

**Passive DR Audit** is the audit performed pursuant to Section III.13.6.1.5.4.

**Passive DR Auditing Period** is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

**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.13.7.1.2 of Market Rule 1.

**PER Proxy Unit** is described in Section III.13.7.1.2.1 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 Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

**Point of Interconnection** shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of 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.

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

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

**Posturing Credits** are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

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

**Principal** is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**Rapid Response Pricing Asset** is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

**Rapid Response Pricing Opportunity Cost** is the NCPC Credit described in Section III.F.2.3.10.

**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.

**Rationing Minimum Limit** is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which an offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

**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) of Market Rule 1.

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

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

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

**Real-Time Demand Reduction Obligation** is defined in Section III.3.2.1(c) of Market Rule 1.

**Real-Time Demand Reduction Obligation Deviation** is defined in Section III.3.2.1(e) of Market Rule 1.

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

**Real-Time Energy Market** means the purchase or sale of energy, purchase of demand reductions, 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(g) of Market Rule 1.

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

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

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

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

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

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

**Real-Time High Operating Limit** is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

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

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

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

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

**Real-Time Loss Revenue** is defined in Section III.3.2.1(l) 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 Offer Change** is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

**Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources)**

**Postured for Reliability** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

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

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

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

**Real-Time Reserve Clearing Price** is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

**Real-Time Reserve Credit** is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement 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 described in Section III.1.7.19 of Market Rule 1.

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

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

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

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

**Reference Level** is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

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

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

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

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

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



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

**Regulation** is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

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

**Regulation Capacity** is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

**Regulation Capacity Requirement** is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

**Regulation Capacity Offer** is an offer by a Market Participant to provide Regulation Capacity.

**Regulation High Limit** is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

**Regulation Low Limit** is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

**Regulation Market** is the market described in Section III.14 of Market Rule 1.

**Regulation Resources** are those Alternative Technology Regulation Resources and Generator Assets that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

**Regulation Service** is the change in output or consumption made in response to changing AGC SetPoints.

**Regulation Service Requirement** is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

**Regulation Service Offer** is an offer by a Market Participant to provide Regulation Service.

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

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

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

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

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

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

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

criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

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

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

**Renewable Technology Resource** is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

**Re-Offer Period** is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, 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 MGTSAs holder that sells, assigns or transfers its rights under its MGTSAs, 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 Quantity For Settlement** is defined in Section III.10.1 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 Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**Seasonal Claimed Capability** is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

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

**Seasonal DR Audit** is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

**Seasonal Peak Demand Resource** is a type of Demand Capacity 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 its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in

the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing 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 committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

**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.C 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.

**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).

**Sponsored Policy Resource** is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.



**Stage One Proposal** is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

**Stage Two Solution** is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

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

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

**Start-Up Fee** is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset 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 Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

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

**Station Going Forward Common Costs** are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

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

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

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

**Storage DARD** is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**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 pursuant to Section III.9. 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.

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

timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

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

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

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

**System Impact Study** is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

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

**System-Wide Capacity Demand Curve** is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

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

Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

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

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

**Ten-Minute Non-Spinning Reserve (TMNSR)** is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

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

**Ten-Minute Reserve Requirement** is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**Ten-Minute Spinning Reserve (TMSR)** is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

**Ten-Minute Spinning Reserve Requirement** is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**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)** is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

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

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

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

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

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

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

**Total Blackstart 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 Reserve Requirement**, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**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 Constraint Penalty Factors** are described in Section III.1.7.5 of Market Rule 1.

**Transmission Credit Limit** is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

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

**Transmission Customer** is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

**Transmission Default Amount** is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

**Transmission Default Period** is defined in Section 3.4.f of the ISO New England Billing Policy.

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

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

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

**Transmission, Markets and Services Tariff (Tariff)** is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

**Transmission Obligations** are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

**Transmission Operating Agreement (TOA)** is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

**Transmission Owner** means a PTO, MTO or OTO.

**Transmission Provider** is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

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

**Transmission Security Analysis Requirement** shall be determined pursuant to Section III.12.2.1.2.

**Transmission Service Agreement (TSA)** is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

**Transmission Upgrade(s)** means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

**UDS** is unit dispatch system software.

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

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



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

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

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

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

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

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

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

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

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

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

**Unsettled FTR Financial Assurance** is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

**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 On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated 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 Cap is \$2,000/MWh.**

**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 pursuant to Section III.9. 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.

**Zonal Capacity Obligation** is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

**Zonal Reserve Requirement** is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

## 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, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance 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, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance 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) The following 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) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.
- (iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR 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) An Establish Claimed Capability Audit may be performed only by a Generator Asset.
- (b) The time and date of an Establish Claimed Capability Audit shall be unannounced.
- (c) For a newly commercial Generator Asset:
  - (i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:
    - 1. Non-intermittent daily cycle hydro;
    - 2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
    - 3. Intermittent Generator Assets
  - (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.
- (d) 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 five 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 one Business Day 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.
- (e) 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.
  - (f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.
  - (g) To conduct an Establish Claimed Capability Audit, the ISO shall:
    - (i) Initiate an Establish 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.
    - (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
    - (iii) 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.
  - (h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

<b>Duration Required for an Establish Claimed Capability Audit</b>	
<b>Type</b>	<b>Claimed Capability Audit Duration (Hrs)</b>
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4



Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

- (i) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.2(h).

**III.1.5.1.3. Seasonal Claimed Capability Audits.**

- (a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.
- (b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:
- (i) Non-intermittent daily hydro; and
  - (ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).
- (c) 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.
- (d) Except as provided in Section III.1.5.1.3(n) 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.
- (e) 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.
- (f) 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 fifth 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.
- (g) 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.
- (h) 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(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.
- (i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

<b>Duration Required for a Seasonal Claimed Capability Audit</b>	
<b>Type</b>	<b>Claimed Capability Audit Duration (Hrs)</b>
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2

Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible (Electric Storage)	2
Hydraulic Turbine-Other	
Hydro-Conventional Weekly	2
Fuel Cell	1
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

- (k) 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.
- (l) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, 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.
- (m) 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.

- (n) 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(f).
  - (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(d)(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(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.
- (o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.3(j).

#### **III.1.5.1.3.1 Seasonal DR Audits.**

- (a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

- (b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.
- (c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:
  - (i) At least once every Capability Demonstration Year;
  - (ii) During the months of April through November;
- (d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:
  - (i) At least once every Capability Demonstration Year;
  - (ii) During the months of December through March.
- (e) A Seasonal DR Audit may be performed either:
  - (i) At the request of a Market Participant as described in subsection (f) below; or
  - (ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.
- (f) If a Market Participant requests a Seasonal DR Audit:
  - (i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.
  - (ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.
  - (iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.
  - (iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
  - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:
  - (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth 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 DR Audit.
  - (iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.
  - (iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

- (h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.
- (i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.
- (j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.
- (k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.
- (l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.
- (m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.
- (n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.
- (o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

#### **III.1.5.1.4. ISO-Initiated Claimed Capability 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 either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both 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 for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.
- (ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset 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 for a Generator Asset 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) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day 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) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.
  - (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
  - (iii) For Generator Assets, 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.
  - (iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
- (f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

<b>Duration Required for an ISO-Initiated Claimed Capability Audit</b>	
<b>Type</b>	<b>Claimed Capability Audit Duration (Hrs)</b>
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4

Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage)	2
Hydraulic Turbine – Other	
Hydro-Conventional Daily Pondage	2
Hydro-Conventional Run of River	
Hydro-Conventional Weekly	
Wind	2
Photovoltaic	
Fuel Cell	
Other Electric Storage (Excludes Hydraulic Turbine – Reversible)	2
Demand Response Resource	1

- (g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource type not listed in Section III.1.5.1.4(f).

### III.1.5.2 ISO-Initiated Parameter Auditing.

- (a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide real-time energy or reserves.
- (b) Generator audits shall be performed using the following methods for the relevant parameter:
- (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 in accordance with Section III.9.5.
  - (vi) **CLAIM30.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
  - (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 electronic Dispatch Instructions.
  - (viii) **Dual Fuel Capability.** A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).
- (c) Demand Response Resource audits shall be performed using the following methods:
- (i) **Maximum Reduction.** The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.
  - (ii) **Demand Response Resource Ramp Rate.** The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.
  - (iii) **Demand Response Resource Start-Up Time.** The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.
  - (iv) **Demand Response Resource Notification Time.** The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.
  - (v) **CLAIM10.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.
  - (vi) **CLAIM30.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
- (d) To conduct an audit based upon historical data, the ISO shall:
- (i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or
  - (ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.

- (e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.
- (f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:
  - (i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.
  - (ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.
- (g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.
- (h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:
  - (i) The 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 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 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 parameter value restriction;
    2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
    3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

### **III.1.5.3 Reactive Capability Audits.**

- (a) Two types of Reactive Capability Audits may be performed:
  - (i) A Lagging Reactive Capability Audit measures the Generator Asset's ability to provide reactive power to the transmission system at a specified real power output.
  - (ii) A Leading Reactive Capability Audit measures the Generator Asset's ability to absorb reactive power from the transmission system at a specified real power output.
- (b) The ISO shall develop a list of Generator Assets that must conduct Reactive Capability Audits.
- (c) Unless otherwise directed by the ISO, Generator Assets that are required to perform Reactive Capability Audits must perform both a Lagging Reactive Capability Audit and a Leading Reactive Capability Audit.
- (d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.
- (e) The Reactive 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.
- (f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.
- (g) Reactive Capability Audits must be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Generator Asset to conduct Reactive Capability Audits more often than every five years if:
  - (i) there is a change in the Generator Asset that may affect the reactive power capability of the Generator Asset;
  - (ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Generator Asset; or
  - (iii) historical data shows that the amount of reactive power that the Generator Asset can provide to or absorb from the transmission system is higher or lower than the latest audit data.
- (h) The Lead Market Participant may request a waiver of the requirement to conduct a Reactive Capability Audit. The ISO, at its sole discretion, will determine whether and for how long a waiver can be granted.

**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** **Transmission Constraint Penalty Factors.**

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is \$10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is \$30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any

transmission constraint is \$30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

### **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, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the 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 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 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 limitations and 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 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.**

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.

**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 review of historical data for non-intermittent daily cycle hydro.
  - (ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.
  - (iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:
    - a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.
    - b. For a Generator Asset that is off-line and not available for commitment shall be zero.
    - c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.
  - (iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

**III.1.7.12 Seasonal DR Audit Value of an Active Demand Capacity Resource.**

- (a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through

November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.

- (b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

**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 endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. 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 Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

**III.1.7.18**            **Ramping.**

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to sanctions for failure to comply as described in **Appendix B**.

**III.1.7.19**            **Real-Time Reserve Designation.**

The ISO shall determine the Real-Time Reserve Designation for each eligible Resource in accordance with this Section III.1.7.19. The Real-Time Reserve Designation shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve.

**III.1.7.19.1**        **Eligibility.**



To be eligible to receive a Real-Time Reserve Designation, a Resource must meet all of the criteria enumerated in this Section III.1.7.19.1. A Resource that does not meet all of these criteria is not eligible to provide Operating Reserve and will not receive a Real-Time Reserve Designation.

- (1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.
- (2) The Resource must not be part of the first contingency supply loss.
- (3) The Resource must not be designated as constrained by transmission limitations.
- (4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)
- (5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

### **III.1.7.19.2 Calculation of Real-Time Reserve Designation.**

#### **III.1.7.19.2.1 Generator Assets.**

##### **III.1.7.19.2.1.1 On-line Generator Assets.**

The Manual Response Rate used in calculations in this section shall be the lesser of the Generator Asset's offered Manual Response Rate and its audited Manual Response Rate as described in Section III.1.5.2.

- (a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.

- (b) **Ten-Minute Non-Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Non-Spinning Reserve shall be zero. For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit).
- (c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

#### **III.1.7.19.2.1.2 Off-line Generator Assets.**

For an off-line Generator Asset that is not a Fast Start Generator, all components of the Real-Time Reserve Designation shall be zero.

- (a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).

- (c) **Thirty-Minute Operating Reserve.** For an off-line Fast Start Generator, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Fast Start Generator's Offered CLAIM30, its CLAIM30, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Thirty-Minute Operating Reserve shall be zero, except during the last thirty minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Thirty-Minute Operating Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires), minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Fast Start Generator pursuant to subsection (b) above.

#### **III.1.7.19.2.2 Dispatchable Asset Related Demand.**

##### **III.1.7.19.2.2.1 Storage DARDs.**

- (a) **Ten-Minute Spinning Reserve.** For a Storage DARD, Ten-Minute Spinning Reserve shall be calculated as the absolute value of the amount of current telemetered consumption.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.
- (c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

##### **III.1.7.19.2.2.2 Dispatchable Asset Related Demand Other Than Storage DARDs.**

- (a) **Ten-Minute Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit). For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

- (b) **Ten-Minute Non-Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit).
- (c) **Thirty-Minute Operating Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (a) above. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Non-Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (b) above.

### **III.1.7.19.2.3 Demand Response Resources.**

For a Demand Response Resource that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2.

#### **III.1.7.19.2.3.1 Dispatched.**

- (a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be

calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction). For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

- (b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction).
- (c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within thirty minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction) minus the Ten-Minute Spinning Reserve quantity calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

#### **III.1.7.19.2.3.2 Non-Dispatched.**

For a Demand Response Resource that is not being dispatched that is not a Fast Start Demand Response Resource, all components of the Real-Time Reserve Designation shall be zero.

- (a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Demand Response Resource's Offered CLAIM10, its CLAIM10, and its Maximum Reduction.

- (c) **Thirty-Minute Operating Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Demand Response Resource's Offered CLAIM30, its CLAIM30, and its Maximum Reduction, minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Demand Response Resource pursuant to subsection (b) above.

**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 Resources 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, consumption, or demand reduction levels of Generator Assets, DARDs, or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and 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.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands 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 or demand reduction capability for the pertinent Operating Day.

**III.1.8** [Reserved.]

**III.1.9** Pre-scheduling.

**III.1.9.1** Offer and Bid Caps and Cost Verification for Offers and Bids.

**III.1.9.1.1** Cost Verification of Resource Offers.~~[Reserved.]~~

The incremental energy values of Supply Offers and Demand Response Resources above \$1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or \$1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than \$1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to \$1,000/MWh, then the adjusted offer for the Resource is set at \$1,000/MWh;

(ii) If the Reference Level value is greater than \$1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

**III.1.9.1.2** Offer and Bid Caps.

(a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at \$2,000/MWh.

(b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.

(c) Supply Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

(d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.

(e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

**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 Generator Asset 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 Generator Assets or Demand Response 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 or Demand Reduction Offers.

#### **III.1.10.1A Energy Market Scheduling.**

The submission of Day-Ahead offers and bids 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) **Locational Demand Bids** – 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 Resources 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~~ Demand Bid Cap and Virtual Cap.

(b) **External Transactions** – All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets 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 submitted under Section III.1.10.7 and 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 ~~External Transaction Cap~~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.

(c) **Generator Asset Supply Offers** – Market Participants selling into the New England Markets from Generator Assets or External Resources may submit Supply Offers or External Transactions for the supply of energy for the following Operating Day. (Coordinated External Transactions shall be submitted to the ISO in accordance with Section III.1.10.7.A of this Market Rule 1.)

Such Supply Offers:

(i) Shall specify the Resource and 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 prices and quantities in a Block may each vary on an hourly basis;

(ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type 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 Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including 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 an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and

~~(vi) Shall not specify an energy offer below the Energy Offer Floor or above the Energy Offer Cap; and~~

(vii) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.

(d) **DARD Demand Bids** – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including 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;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

~~(iv) Shall not specify a bid price below the Energy Offer Floor or above the Energy Offer Cap;~~

~~(iv)~~ (iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers** – Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is above the Energy Offer Cap, below the Energy Offer Floor, or below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.

(f) **Demand Reduction Threshold Price** – The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

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

- (b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.
- (c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.
- (d) A historic threshold price  $P_{th}$  shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.
- (e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

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

where  $FPI_h$  is the historic fuel price index for the same month of the previous year, and  $FPI_c$  is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15<sup>th</sup> day of the month preceding the Demand Reduction Threshold Price's effective date.

- (g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction 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, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) **Load Estimate** – 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) **Prorated Supply** – In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction 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, Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction 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, Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) **Prorated Demand** – 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) **Virtuals** – 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, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such



Resources 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 supply or consumption and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(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 and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

(c) Market Participants offering energy from 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) 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.

#### **III.1.10.3 Self-Scheduled Resources.**

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD 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. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource shall not be Self-Scheduled.

#### **III.1.10.4 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 and Section III.1.10.7.A 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.1.10.5 Dispatchable Asset Related Demand.**

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

- (i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;
- (ii) 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;
- (iii) abide by the ISO maintenance coordination procedures; and

- (iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

#### **III.1.10.6 Electric Storage**

that A storage facility is a facility that is capable of receiving electricity from the grid and storing the energy for later injection of electricity back to the grid. A storage facility may participate in the New England Markets as described below.

- (a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:
  - (i) comprise one or more storage facilities at the same point of interconnection;
  - (ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;
  - (iii) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;
  - (iv) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;
  - (v) settle its injection of electricity to the grid as a Generator Asset and its receipt of electricity from the grid as a DARD; and
  - (vi) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.
  
- (b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:
  - (i) satisfy the requirements applicable to an Electric Storage Facility; and
  - (ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and
  - (iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.
  
- (c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

- (i) satisfy the requirements applicable to an Electric Storage Facility;
  - (ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;
  - (iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;
  - (iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;
  - (v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;
  - (vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;
  - (vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and
  - (viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).
- (d) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.
- (e) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.
- (f) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered

and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

(g) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.

(h) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

#### **III.1.10.7 External Transactions.**

The provisions of this Section III.1.10.7 do not apply to Coordinated 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) [Reserved.]

(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) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) 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.1.10.7.A Coordinated External Transactions.**

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated NERC E-Tag at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless applicable procedures governing the Emergency permit the transaction to be scheduled.

#### **III.1.10.7.B Coordinated Transactions Scheduling Threshold Trigger to Tie Optimization**

(a) Background and Overview

This Section III.1.10.B describes the process for filing amendments to the Transmission, Markets and Services Tariff under Section 205 of the Federal Power Act in the event that the production cost savings of the ISO's interchange on the New York – New England AC Interface, including the Northport/Norwalk Line, following the implementation of an inter-regional interchange scheduling process known as Coordinated Transaction Scheduling, are not satisfactory. The determination of whether savings are satisfactory will be based on actions, thresholds and triggers described in this Section III.1.10.7.B. If pursuant to the actions, thresholds and triggers described in this Section III.1.10.7.B, the production costs savings of Coordinated Transaction Scheduling are not satisfactory, and a superior alternative has not become known, the ISO will file tariff amendments with the Commission to implement the inter-regional interchange scheduling process described to the ISO stakeholders in 2011 as Tie Optimization.

If, pursuant to the timetables presented, the ISO determines the thresholds described herein have not triggered, the process for filing amendments to the ISO tariff as described herein ceases, the provisions of this Section III.1.10.7.B become null and void and the ISO will continue to implement Coordinated Transaction Scheduling unless and until future Section 205 filings are pursued to amend Coordinated Transaction Scheduling.

(b) The Two-Year Analysis

Within 120 days of the close of the first and second years following the date that Coordinated Transaction Scheduling as an interface scheduling tool is activated in the New England and New York wholesale electricity markets, the External Market Monitor will develop, for presentation to and comment by, New England stakeholders, an analysis, of:

(i) the Tie Optimization interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the ISO and New York Independent System Operator received an infinite number of zero bids in the Coordinated Transaction Scheduling process, which utilizes the supply curves and forecasted prices for each market; and

(ii) an optimal interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the two ISOs had an infinite number of zero bids in the Coordinated Transaction Scheduling process, but utilizing actual real-time prices from each market rather than the forecasted prices that were used in the Coordinated Transaction Scheduling process.

The bid production cost savings associated with the Tie Optimization interchange as developed in (i) above for the second year following the date that Coordinated Transaction Scheduling is activated in the New England and New York wholesale electricity markets will reveal the “foregone” production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(b)(1) formula as the term “b.” The difference in bid production cost savings between (i) and (ii) above will reveal the “foregone” bid production cost savings of the Tie Optimization interchange as developed in (i) above rather than an optimal interchange as developed in (ii) above, represented in the Section III.1.10.7.B(b)(1) formula as the term “a.”

This analysis will be consistent with presentations made by the External Market Monitor to the New England stakeholders during 2011 on the issue of the benefits of Coordinated Transaction Scheduling.

- (1) Using the above calculations, the External Market Monitor will compute the following ratio:

b/a

If, the ratio b/a is greater than 60% and b is greater than \$3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(c) Improving Coordinated Transaction Scheduling

- (1) If the ratio, developed pursuant to Section III.1.10.7.B(b)(1), is greater than 60% and b is greater than \$3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

- (2) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

- (3) If the ISO declares that the threshold has triggered, the External Market Monitor will provide recommendations of adjustments to the design or operation of Coordinated Transaction Scheduling to improve the production cost savings available from its implementation.

- (4) The ISO, considering the input of the New England stakeholders and the recommendation of the External Market Monitor, will develop and implement adjustments to Coordinated Transaction Scheduling. To the extent tariff revisions are necessary to implement the adjustments to Coordinated Transaction Scheduling, the ISO will file such revisions with the Commission as a compliance filing in the Coordinated Transaction Scheduling docket. If no adjustments to Coordinated Transaction Scheduling have been identified, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing.

(d) The Second Analysis

- (1) Within 120 days of the close of the twelve months following the date that the adjustments to Coordinated Transaction Scheduling, developed under Section III.1.10.7.B(c), are activated in the New England and New York wholesale electricity markets, the External Market Monitor will present a second

analysis to New England stakeholders. The analysis will be consistent with the analysis described in Section III.1.10.7.B(b) but will develop bid production cost savings for the twelve month period during which the adjustments developed in Section III.1.10.7.B(c) are in place.

(2) The bid production cost savings associated with the Tie Optimization interchange as developed in Section III.1.10.7.B(d)(1) will reveal the “foregone” bid production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(d)(3) formula as the term “b.” The difference in bid production cost savings between the Tie Optimization interchange and the optimal interchange, as developed in Section III.1.10.7.B(d)(1), will reveal the “foregone” bid production cost savings of the Tie Optimization interchange rather than the optimal interchange, represented in the Section III.1.10.7.B(d)(3) formula as the term “a.”

(3) Using the above calculations, the External Market Monitor will compute the following ratio:

$$b/a$$

If the ratio  $b/a$  is greater than 60% and  $b$  is greater than \$3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(4) If the ratio  $b/a$  is greater than 60% and  $b$  is greater than \$3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(5) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(6) If the ISO declares the threshold has triggered, considering the input of the stakeholders and the recommendation of the External Market Monitor, the ISO will determine whether a superior alternative has been proposed. If the ISO and the New York Independent System Operator both determine a superior alternative has been proposed, the ISO will prepare tariff amendments to be filed with the Commission to implement the superior alternative, and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for

NEPOOL review of tariff amendments and will not pursue the balance of the actions required by this Section III.1.10.7.B.

(7) If the ISO determines a superior alternative has not been proposed, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing. Tie Optimization was described for stakeholders in the *Design Basis Document* for NE/NY Inter-Regional Interchange Scheduling presented at a NEPOOL Participants Committee meeting on June 10, 2011.

(e) The Compliance Filing

The ISO will develop tariff language to implement the inter-regional interchange scheduling practice known as Tie Optimization through a compliance filing with the Commission and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments.

**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 Resources and to direct that schedules be changed to address an actual or potential 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 Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. 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) 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 ISO New England Manual M-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. The External Transaction re-offer provisions of this Section III.1.10.9(c) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) 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 Generator Assets), and the quantity and price pairs of its Blocks may be modified.
- (ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

(e) 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. A Market Participant may not request to Self-Schedule a Demand Response Resource. A Market Participant may cancel the Self-Schedule of a

Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

(f) 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(c), 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 at a specified value. 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 at or above the requested amount for the hour in question.

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

(i) 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 or Consumption and Demand Reduction.**

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) 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; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) 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 Dispatchable Resources.**

With the exception of Settlement Only Resources, Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, nuclear-powered Resources and photovoltaic Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.

2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

- (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 Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable 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 for a Dispatchable Resource 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.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind and hydro Intermittent Power Resources that are not Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

(i) A wind or hydro Intermittent Power Resource not capable of receiving and responding to electronic Dispatch Instructions will be manually dispatched.

(ii) A Market Participant may elect, but is not required, to have a wind or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.

(iii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.

(f) The ISO may request that dual-fuel Generator Assets 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-fuel Generator Assets 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-fuel Generator Assets 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 Dispatchability Requirements for Intermittent Power Resources.**

- (a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.
- (b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redeclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

#### **III.1.11.6 Non-Dispatchable Resources.**

Non-Dispatchable Resources are subject to the following requirements:

- (a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource 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.
- (b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

#### **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, DRR Aggregation 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 electric 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 resources 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 Offer Data, 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. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices shall be determined every five minutes and 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. 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 zonal 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 power flow solution produced by the State Estimator for the pricing interval, 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 Adjustment for Rapid Response Pricing Assets.**

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO, is in a dispatchable mode, and is not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee, No-Load Fee, or Interruption Cost is specified in the submitted Offer Data, a value of zero shall be used; if no Minimum Run Time or Minimum Reduction Time is specified in the submitted Offer Data, or if the submitted Minimum Run Time or Minimum Reduction Time is less than 15 minutes, a duration of 15 minutes shall be used; and the energy offer after adjustment shall not exceed \$2,000/MWh~~the Energy Offer Cap~~.

- (a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Binary Storage DARD, its Minimum Consumption Limit shall be set to zero; if the Rapid Response Pricing Asset is a Fast Start Demand Response Resource, its Minimum Reduction shall be set to zero.
- (b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.
- (c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.
- (d) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.

(e) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.

### **III.2.5 Calculation of Nodal Real-Time 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 power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), 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 Generator Assets (excluding Settlement Only Resources), Demand Response Resources, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demands with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply or consume 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 output 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.2.7A(c); and (5) the effect on transmission losses caused by the increment of load, generation and demand reduction. 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. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed for every five-minute interval, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the pricing 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.

### **III.2.6 Calculation of Nodal Day-Ahead 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, Demand Reduction 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 an optimization method to minimize energy cost, 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 output 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 supply. 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.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: 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 supply at the Generator Asset's Economic Maximum Limit and demand reduction at the Demand Response Resource's Maximum Reduction, 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 External Transaction Cap ~~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, Demand Reduction 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 Generator Assets, dispatched Demand Response Resources, 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 Generator Assets (excluding Settlement Only Resources),

dispatched Demand Response Resources, 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 supply (including fixed External Transaction purchases) with all possible Generator Assets off line and with all remaining Generator Assets at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess 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 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 Generator Assets 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 Generator Assets (excluding Settlement Only Resources); and

(iii) If power balance not achieved in step (ii), set LMP values to Energy Offer Floor and reduce all Generator Assets 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 and DRR Aggregation Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone or DRR Aggregation Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and DRR Aggregation 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, Dispatch Zones, and Reserve Zones and add or subtract Reliability Regions, Load Zones, Dispatch 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 is greater than 75 percent of the total 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 obtain Operating Reserve in Real-Time to serve Operating Reserve requirements for the system and each Reserve Zone on a jointly optimized basis with the calculation of nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to maximize social surplus, 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 Generator Assets (excluding Settlement Only Resources), Demand Response Resources and Dispatchable Asset Related Demands 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 meet the system and zonal Operating Reserve requirements or there is a deficiency in available Operating Reserve, in which case Real-Time Reserve Clearing Prices shall be set as described in Section III.2.7A(b) and Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands that were re-dispatched to meet the applicable Operating Reserve requirement. The Real-Time Reserve Opportunity Cost of a Resource shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve.

(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 the following Reserve Constraint Penalty Factors:

<b>Real-Time Requirement</b>	<b>Reserve Constraint Penalty Factor</b>
Zonal Reserve Requirement (combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone)	\$250/MWh
Minimum Total Reserve Requirement (does not include Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	\$1000/MWh
Total Reserve Requirement (includes Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	\$250/MWh
Ten-Minute Reserve Requirement (combined amount of TMSR and TMNSR required system-wide)	\$1500/MWh

Ten-Minute Spinning Reserve Requirement (amount of TMSR required system-wide)	\$50/MWh
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The Reserve Constraint Penalty Factors 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 for every five-minute interval, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of zonal Real-Time Reserve Clearing Prices based on system conditions for the pricing 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.

**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 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**

**Table of Contents**

III.A.1.	Introduction and Purpose: Structure and Oversight: Independence
III.A.1.1.	Mission Statement
III.A.1.2.	Structure and Oversight
III.A.1.3.	Data Access and Information Sharing
III.A.1.4.	Interpretation
III.A.1.5.	Definitions
III.A.2.	Functions of the Market Monitor
III.A.2.1.	Core Functions of the Internal Market Monitor and External Market Monitor
III.A.2.2.	Functions of the External Market Monitor
III.A.2.3.	Functions of the Internal Market Monitor
III.A.2.4.	Overview of the Internal Market Monitor's Mitigation Functions
III.A.2.4.1.	Purpose
III.A.2.4.2.	Conditions for the Imposition of Mitigation Measures
III.A.2.4.3.	Applicability
III.A.2.4.4.	Mitigation Not Provided for Under This <i>Appendix A</i>
III.A.2.4.5.	Duration of Mitigation
III.A.3.	Consultation Prior to Determination of Reference Levels for Physical Parameters and Financial Parameters of Resources; Fuel Price Adjustments
III.A.3.1.	Consultation Prior to Offer
III.A.3.2.	Dual Fuel Resources
III.A.3.3.	Market Participant Access to its Reference Levels
III.A.3.4.	Fuel Price Adjustments
III.A.4.	Physical Withholding
III.A.4.1.	Identification of Conduct Inconsistent with Competition

- III.A.4.2. Thresholds for Identifying Physical Withholding
  - III.A.4.2.1. Initial Thresholds
  - III.A.4.2.2. Adjustment to Generating Capacity
  - III.A.4.2.3. Withholding of Transmission
  - III.A.4.2.4. Resources in Congestion Areas

III.A.4.3. Hourly Market Impacts

III.A.5. Mitigation

- III.A.5.1. Resources with Capacity Supply Obligations
  - III.A.5.1.1. Resources with Partial Capacity Supply Obligations

- III.A.5.2. Structural Tests
  - III.A.5.2.1. Pivotal Supplier Test
  - III.A.5.2.2. Constrained Area Test

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market

- III.A.5.5. Mitigation by Type
  - III.A.5.5.1. General Threshold Energy Mitigation
    - III.A.5.5.1.1. Applicability
    - III.A.5.5.1.2. Conduct Test
    - III.A.5.5.1.3. Impact Test
    - III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test
  - III.A.5.5.2. Constrained Area Energy Mitigation
    - III.A.5.5.2.1. Applicability
    - III.A.5.5.2.2. Conduct Test
    - III.A.5.5.2.3. Impact Test
    - III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test
  - III.A.5.5.3. Manual Dispatch Energy Mitigation
    - III.A.5.5.3.1. Applicability
    - III.A.5.5.3.2. Conduct Test
    - III.A.5.5.3.3. Consequence of Failing the Conduct Test
  - III.A.5.5.4. General Threshold Commitment Mitigation
    - III.A.5.5.4.1. Applicability
    - III.A.5.5.4.2. Conduct Test
    - III.A.5.5.4.3. Consequence of Failing Conduct Test



- III.A.5.5.5. Constrained Area Commitment Mitigation
          - III.A.5.5.5.1. Applicability
          - III.A.5.5.5.2. Conduct Test
          - III.A.5.5.5.3. Consequence of Failing Test
        - III.A.5.5.6. Reliability Commitment Mitigation
          - III.A.5.5.6.1. Applicability
          - III.A.5.5.6.2. Conduct Test
          - III.A.5.5.6.3. Consequence of Failing Test
        - III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation
          - III.A.5.5.7.1. Applicability
          - III.A.5.5.7.2. Conduct Test
          - III.A.5.5.7.3. Consequence of Failing Conduct Test
        - III.A.5.5.8. Low Load Cost
      - III.A.5.6. Duration of Energy Threshold Mitigation
      - III.A.5.7. Duration of Commitment Mitigation
      - III.A.5.8. Duration of Start-Up Fee and No-Load Mitigation
      - III.A.5.9. Correction of Mitigation
      - III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process
- III.A.6. Physical and Financial Parameter Offer Thresholds
  - III.A.6.1. Time-Based Offer Parameters
  - III.A.6.2. Financial Offer Parameters
  - III.A.6.3. Other Offer Parameters
- 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 Parameter
  - III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Supply Offers
    - III.A.7.2.1. Order of Reference Level Calculation
    - III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation
  - III.A.7.3. Accepted Offer-Based Reference Level
  - III.A.7.4. LMP-Based Reference Level

- III.A.7.5. Cost-based Reference Level
  - III.A.7.5.1. Estimation of Incremental Operating Cost
- III.A.8. [Reserved.]
- III.A.9. Regulation
- III.A.10. Demand Bids
- III.A.11. Mitigation of Increment Offers and Decrement Bids
  - III.A.11.1. Purpose
  - III.A.11.2. Implementation
    - III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids
  - III.A.11.3. Mitigation Measures
  - III.A.11.4. Monitoring and Analysis of Market Design and Rules
- III.A.12. Cap on FTR Revenues
- 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
  - III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market
  - III.A.13.3. Monitoring of Transmission Facility Outage Scheduling
  - III.A.13.4. Monitoring of Forward Reserve Resources
  - III.A.13.5. Imposition of Sanctions
- III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement
- III.A.15. Request for Additional Cost Recovery
  - III.A.15.1. Filing Right
  - III.A.15.2. Contents of Filing
  - III.A.15.3. Review by Internal Market Monitor Prior to Filing
  - III.A.15.4. Cost Allocation

- III.A.16. ADR Review of Internal Market Monitor Mitigation Actions
  - III.A.16.1. Actions Subject to Review
  - III.A.16.2. Standard of Review
  
- III.A.17. Reporting
  - III.A.17.1. Data Collection and Retention
  - III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor
    - III.A.17.2.1. Monthly Report
    - III.A.17.2.2. Quarterly Report
    - III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market
    - III.A.17.2.4. Annual Review and Report by the Internal Market Monitor
  - III.A.17.3. Periodic Reporting by the External Market Monitor
  - III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications with Government Agencies
    - III.A.17.4.1. Routine Communications
    - III.A.17.4.2. Additional Communications
    - III.A.17.4.3. Confidentiality
  - III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators
  
- III.A.18. Ethical Conduct Standards
  - III.A.18.1. Compliance with ISO New England Inc. Code of Conduct
  - III.A.18.2. Additional Ethical Conduct Standards
    - III.A.18.2.1. Prohibition on Employment with a Market Participant
    - III.A.18.2.2. Prohibition on Compensation for Services
    - III.A.18.2.3. Additional Standards Application to External Market Monitor
  
- III.A.19. Protocols on Referrals to the Commission of Suspected Violations
  
- III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes

- III.A.21. Review of Offers From New Resources in the Forward Capacity Market
  - III.A.21.1. Offer Review Trigger Prices
    - III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction
    - III.A.21.1.2. Calculation of Offer Review Trigger Prices
  - III.A.21.2. New Resource Offer Floor Prices and Offer Prices
  - III.A.21.3. Special Treatment of Certain Out-of-Market Capacity Resources in the Eighth Forward Capacity Auction
- III.A.22. [Reserved]
- III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market
  - III.A.23.1. Pivotal Supplier Test
  - III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal
  - III.A.23.3. Pivotal Supplier Test Notification of Results
  - III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test
- III.A.24 Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market
- EXHIBIT 1 [Reserved]
- EXHIBIT 2 [Reserved]
- EXHIBIT 3 [Reserved]
- EXHIBIT 4 [Reserved]
- 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, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this *Appendix A*, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

**III.A.3.2. Dual Fuel Resources.**

In evaluating bids or offers under this *Appendix A* for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

- (a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.
- (b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

#### **III.A.3.3. Market Participant Access to its Reference Levels.**

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

#### **III.A.3.4. Fuel Price Adjustments.**

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer

or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus \$2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1 or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2



2 or more	6
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#### **III.A.4. Physical Withholding.**

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

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

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

- (a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
- (b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,
- (c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
- (d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

##### **III.A.4.2. Thresholds for Identifying Physical Withholding.**

###### **III.A.4.2.1. Initial Thresholds.**

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

- (a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
- (b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

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

**III.A.4.2.2. Adjustment to Generating Capacity.**

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

**III.A.4.2.3. Withholding of Transmission.**

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

**III.A.4.2.4. Resources in Congestion Areas.**

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

**III.A.4.3. Hourly Market Impacts.**

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

**III.A.5. Mitigation.**

**III.A.5.1. Resources with Capacity Supply Obligations.**

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

**III.A.5.1.1. Resources with Partial Capacity Supply Obligations.**

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

- (a) all Supply Offer parameters shall be reviewed for economic withholding;
- (b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;
- (c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

**III.A.5.2. Structural Tests.**

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

- (a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;
- (b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

**III.A.5.2.1. Pivotal Supplier Test.**

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

#### **III.A.5.2.2. Constrained Area Test.**

A Resource is considered to be within a constrained area if:

- (a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;
- (b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than \$25/MWh.

#### **III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.**

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

#### **III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.**

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

- (a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
- (b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

#### **III.A.5.5. Mitigation by Type.**

##### **III.A.5.5.1. General Threshold Energy Mitigation.**

###### **III.A.5.5.1.1. Applicability.**

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

###### **III.A.5.5.1.2. Conduct Test.**

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or \$100/MWh, whichever is lower. Offer block prices below \$25/MWh are not subject to the conduct test.

###### **III.A.5.5.1.3. Impact Test.**

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or \$100/MWh, whichever is lower as determined by the real-time impact test.

###### **III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.**

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

**III.A.5.5.2. Constrained Area Energy Mitigation.**

**III.A.5.5.2.1. Applicability.**

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

**III.A.5.5.2.2. Conduct Test.**

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or \$25/MWh, whichever is lower.

**III.A.5.5.2.3. Impact Test.**

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or \$25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

**III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.**

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

**III.A.5.5.3. Manual Dispatch Energy Mitigation.**

**III.A.5.5.3.1. Applicability.**

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

**III.A.5.5.3.2. Conduct Test.**

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

**III.A.5.5.3.3. Consequence of Failing the Conduct Test.**

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

**III.A.5.5.4. General Threshold Commitment Mitigation.**

**III.A.5.5.4.1. Applicability.**

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

**III.A.5.5.4.2. Conduct Test.**

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

**III.A.5.5.4.3. Consequence of Failing Conduct Test.**

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

**III.A.5.5.5. Constrained Area Commitment Mitigation.**

**III.A.5.5.5.1. Applicability.**

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

**III.A.5.5.5.2. Conduct Test.**

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

**III.A.5.5.3. Consequence of Failing Test.**

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

**III.A.5.5.6. Reliability Commitment Mitigation.**

**III.A.5.5.6.1. Applicability.**

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

- i. local first contingency;
- ii. local second contingency;
- iii. VAR or voltage;
- iv. distribution (Special Constraint Resource Service);
- v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

**III.A.5.5.6.2. Conduct Test.**

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

**III.A.5.5.6.3. Consequence of Failing Test.**

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

**III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.**

**III.A.5.5.7.1. Applicability.**



Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

**III.A.5.5.7.2. Conduct Test.**

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

**III.A.5.5.7.3. Consequence of Failing Conduct Test.**

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

**III.A.5.5.8. Low Load Cost.**

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

- (a) If the Resource is starting from an offline state, the Start-Up Fee;
- (b) The sum of the No Load Fees for the Commitment Period; and
- (c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

**III.A.5.6. Duration of Energy Threshold Mitigation.**

Any mitigation imposed pursuant to Sections III.A.5.5.1 “General Threshold Energy Mitigation” or III.A.5.5.2 “Constrained Area Energy Mitigation” is in effect for the following duration:

- (a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:
  - i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,
  - ii. for constrained area energy mitigation, the Resource is not located within a constrained area.
- (b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 “Constrained Area Energy Mitigation”), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 “Manual Dispatch Energy Mitigation” is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource’s Node.

**III.A.5.7. Duration of Commitment Mitigation.**

Any mitigation imposed pursuant to Sections III.A.5.5.4 “General Threshold Commitment Mitigation”, III.A.5.5.5 “Constrained Area Commitment Mitigation”, or III.A.5.5.6 “Reliability Commitment Mitigation” is in effect for the duration of the Commitment Period.

**III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.**

Any mitigation imposed pursuant to Sections III.A.5.5.7 “Start-Up Fee and No-Load Fee Mitigation” is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

**III.A.5.9. Correction of Mitigation.**

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as

part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

**III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.**

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

**III.A.6. Physical and Financial Parameter Offer Thresholds.**

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

**III.A.6.1. Time-Based Offer Parameters.**

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

**III.A.6.2. Financial Offer Parameters.**

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

**III.A.6.3. Other Offer Parameters.**

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

**III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.**

Market Participants are responsible for providing the Internal Market Monitor with all the information and data necessary for the Internal Market Monitor to calculate up-to-date Reference Levels for each of a Market Participant's 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, [Interruption Costs](#) 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 an [Supply Offer](#) according to the following hierarchy, under which the first method that can be calculated is used:

- (a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
- (b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
- (c) cost-based Reference Levels pursuant to Section III.A.7.5.

#### **III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.**

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

- (a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
- (b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
- (c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
- (d) For any Operating Day for which, during the previous 90 days:
  - (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
  - (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of

operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.

~~(iii) The Market Participant submits a fuel price pursuant to Section III.A.3.4.(e) When in any hour the incremental energy parameter of an offer, including adjusted offers pursuant to Section III.2.4, is greater than \$1,000/MWh.~~

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For the purposes of this subsection:

- i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.
  - ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.
  - iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.
  - iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.
- (e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.
- (f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:
- (i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,
  - (ii) No-Load Fee or its corresponding fuel blends,
  - (iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,

- (iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and
- (v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

#### **III.A.7.3. Accepted Offer-Based Reference Level.**

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

#### **III.A.7.4. LMP-Based Reference Level.**

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

#### **III.A.7.5. Cost-Based Reference Level.**

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant 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. All cost estimates, including opportunity cost estimates, must be quantified and analytically supported.

- (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/Reduction:

$(\text{incremental heat rate} * \text{fuel costs}) + (\text{emissions rate} * \text{emissions allowance price}) + \text{variable operating and maintenance costs} + \text{opportunity costs}.$

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; and
- (d) reducing electricity consumption.

No-Load:

$(\text{no-load fuel use} * \text{fuel costs}) + (\text{no-load emissions} * \text{emission allowance price})$



+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up/Interruption:

(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. [Reserved.]**

### **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 the Energy Market as outlined below:

- (a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.
- (b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as:  $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$ . The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.
- (c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology

intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

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

### **III.A.11. Mitigation of Increment Offers and Decrement Bids.**

#### **III.A.11.1. Purpose.**

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

#### **III.A.11.2. Implementation.**

##### **III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.**

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not

be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

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

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

#### **III.A.11.3. Mitigation Measures.**

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

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

- (i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.
- (ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.
- (iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

#### **III.A.11.4. Monitoring and Analysis of Market Design and Rules.**

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

### **III.A.12. Cap on FTR Revenues.**

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

### **III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.**

#### **III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.**

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

- (a) [Reserved].
- (b) Section III.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.
- (c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.
- (d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.
- (e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.

(f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

**III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.**

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

**III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.**

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

**III.A.13.4. Monitoring of Forward Reserve Resources.**

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this *Appendix A*. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

**III.A.13.5. Imposition of Sanctions.**

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

**III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.**

Article 5 of the form of Cost-of-Service Agreement in *Appendix I* to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Market 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. Cost Recovery Request Following Capping.**

If as a result of an offer being capped under Section III.1.9, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was capped, the Market Participant may, within 20 days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit an additional cost recovery request to the Internal Market Monitor.

A request under this Section III.A.15 may seek recovery of additional costs incurred for the duration of the period of time for which the Resource was operated at the cap.

#### **III.A.15.1.1. Timing and Contents of Request.**

Within 20 days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant requesting additional cost recovery under this Section III.A.15.1 shall submit to the Internal Market Monitor a request in writing detailing: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data, documentation and calculations for those costs; and (ii) an explanation of why the actual costs of operating the Resource exceeded the capped costs.

#### **III.A.15.1.2. Review by Internal Market Monitor.**

To evaluate a Market Participant's request, the Internal Market Monitor shall use the data, calculations and explanations provided by the Market Participant to verify the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, using the same standards and methodologies the Internal Market Monitor uses to evaluate requests to update Reference Levels under Section III.A.3 of Appendix A. To the extent the Market Participant's request warrants additional cost recovery, the Internal Market Monitor shall reflect that adjustment in the Resource's Reference Levels for

the period covered by the request. The ISO shall then re-apply the cost verification and capping formulas in Section III.1.9 using the updated Reference Levels to re-calculate the adjustments to the Market Participant's offers required thereunder, and then shall calculate additional cost recovery using the adjusted offer values.

Within 20 days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the Market Participant's request, detailing (i) the extent to which it agrees with the request with supporting explanation, and (ii) a calculation of the additional cost recovery. Changes to credits and charges resulting from an additional cost recovery request shall be included in the Data Reconciliation Process.

**III.A.15.1.3. Cost Allocation.**

The ISO shall allocate charges to Market Participants for payment of any additional cost recovery granted under this Section III.A.15.1 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.15.21. Section 205 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, as a result of a request under Section III.A.15.1 being denied in whole or in part despite having submitted a Supply Offer at the Energy Offer Cap,

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a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the Supply Offer offer was mitigated or during which the Resource was operated at the Section III.A.15.1 request was denied the Energy Offer Cap, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. For filings to address cost recovery under Section III.A.15.2(a), the filing must be made within sixty days of receipt of the first Invoice issued containing credits or charges for the applicable Operating Day. For filings to address cost recovery under Section III.A.15.2(b), the filing must be made within sixty days of

receipt of the first Invoice issued that reflects the denied request for additional cost recovery under Section III.A.15.1.

A request under this Section III.A.15.2 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having a Section III.A.15.1 request denied~~submitted a Supply Offer at the Energy Offer Cap~~, costs incurred for the duration of the period of time addressed in the Section III.A.15.1 request~~for which the Resource was operated at the Energy Offer Cap~~.

#### **III.A.15.2.1. Contents of Filing.**

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource, as reflected in the original offer and to the extent not recovered under Section III.A.15.1, exceeded the costs as reflected in the capped offer~~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.15.2.23. Review by Internal Market Monitor Prior to Filing.**

Within twenty days of the receipt of the applicable 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.15.2 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2.1 (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.15.2 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.15.2.

#### **III.A.15.2.34. 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 metered demand reported to the ISO.

### **III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.**

#### **III.A.17.2.1. Monthly Report.**

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

#### **III.A.17.2.2. Quarterly Report.**

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this *Appendix A* and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility

commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this *Appendix A*.

**III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.**

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this *Appendix A*.

**III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.**

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

### **III.A.17.3. Periodic Reporting by the External Market Monitor.**

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

- (i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.
- (ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.
- (iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.
- (iv) Review and assessment of the effectiveness of *Appendix A* and the administration of *Appendix A* by the Internal Market Monitor for consistency and compliance with the terms of *Appendix A*.
- (v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

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

### **III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.**

**III.A.17.4.1. Routine Communications.**

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

**III.A.17.4.2. Additional Communications.**

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

- (a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;
- (b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;
- (c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,
- (d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

**III.A.17.4.3. Confidentiality.**

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

**III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.**

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

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

Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

**III.A.18. Ethical Conduct Standards.**

**III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.**

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

**III.A.18.2. Additional Ethical Conduct Standards.**

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

**III.A.18.2.1. Prohibition on Employment with a Market Participant.**

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

**III.A.18.2.2. Prohibition on Compensation for Services.**

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

**III.A.18.2.3. Additional Standards Applicable to External Market Monitor.**

In addition to the standards referenced in the remainder of this Section 18 of *Appendix A*, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the

External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

**III.A.19. Protocols on Referral to the Commission of Suspected Violations.**

- (A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.
- (B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information
- (1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);
  - (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
  - (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
  - (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
  - (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;



- (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
  - (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

**III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.**

- (A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.
- (B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information.
  - (1) A detailed narrative describing the perceived market design flaw(s);
  - (2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;
  - (3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;

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

**III.A.21. Review of Offers From New Resources in the Forward Capacity Market.**

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

**III.A.21.1. Offer Review Trigger Prices.**

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8 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 Forward Capacity Auction.**

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the twelfth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2021) shall be as follows:

<b>Generating Capacity Resources</b>	
<b>Technology Type</b>	<b>Offer Review Trigger Price (\$/kW-month)</b>
combustion turbine	\$6.503
combined cycle gas turbine	\$7.856

on-shore wind	\$11.025
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<b>Demand Capacity Resources - Commercial and Industrial</b>	
<b>Technology Type</b>	<b>Offer Review Trigger Price (\$/kW-month)</b>
Load Management and/or previously installed Distributed Generation	\$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	\$0.000

<b>Demand Capacity Resources – Residential</b>	
<b>Technology Type</b>	<b>Offer Review Trigger Price (\$/kW-month)</b>
Load Management	\$7.559
previously installed Distributed Generation	\$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	\$0.000

<b>Other Resources</b>	
All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types, the resource’s Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability, the Offer

Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

#### **III.A.21.1.2. Calculation of Offer Review Trigger Prices.**

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. 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 Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<b>Cost Component</b>	<b>Index</b>
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"
steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay: <ul style="list-style-type: none"> <li>- Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</li> <li>- On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</li> </ul>
other labor	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: <ul style="list-style-type: none"> <li>- Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</li> <li>- On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</li> </ul>
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"

gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"
fuel inventories	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<b>Cost Component</b>	<b>Index</b>
labor, administrative and general	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: <ul style="list-style-type: none"> <li>- Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</li> <li>- On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</li> </ul>
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

(3) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 above will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub On-Peak electricity prices for the months in the Capacity Commitment Period beginning June 1, 2021, as published by ICE.

(5) Renewable energy credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

**III.A.21.2. New Resource Offer Floor Prices and Offer Prices.**

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be \$0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an

investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax



treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor

does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

**III.A.22.** [Reserved.]

**III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.**

### **III.A.23.1. Pivotal Supplier Test.**

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

- (a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;
- (b) For each modeled import-constrained Capacity Zone, the greater of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
- (c) For each modeled export-constrained Capacity Zone, the lesser of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone plus, for each external interface connected to the export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Maximum Capacity Limit of the export-constrained Capacity Zone, and;

- (d) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

- (e) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone; and
- (f) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

**III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.**

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

- (a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.
- (b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

**III.A.23.3. Pivotal Supplier Test Notification of Results.**

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

**III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.**

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Capacity Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, “control” or “controlled” means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

**III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.**

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

- i. The annual capacity revenue from the Lead Market Participant’s total FCA Qualified

Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than

- ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then
- iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

- iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.
- v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.
- vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, “control” or “controlled” means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

**SECTION III  
MARKET RULE 1**

**APPENDIX F  
NET COMMITMENT PERIOD COMPENSATION ACCOUNTING**



**APPENDIX F**  
**NCPC ACCOUNTING**  
Table of Contents

III.F.1. General

III.F.2. NCPC Credits

III.F.2.1. Day-Ahead Energy Market NCPC Credits

III.F.2.1.1. Eligibility for Credit.

III.F.2.1.2. Settlement Period.

III.F.2.1.3. Eligible Quantity.

III.F.2.1.3.A Hourly Bid

III.F.2.1.4. Hourly Cost.

III.F.2.1.5. Hourly Revenue.

III.F.2.1.6. General Credit Calculation.

III.F.2.1.7. Credit Calculation for Fast Start Generators, Flexible DNE Dispatchable Generators, Fast Start Demand Response Resources and Binary Storage DARDs Based on Daily Starts, and for Continuous Storage Generator Assets and Continuous Storage DARDs.

III.F.2.2. Real-Time Energy Market NCPC Credits

III.F.2.2.1. Eligibility for Credit.

III.F.2.2.2. Real-Time Commitment NCPC Credits.

III.F.2.2.2.1. Settlement Period.

III.F.2.2.2.2. Eligible Quantity.

III.F.2.2.2.3. Interval Cost.

III.F.2.2.2.3.A Interval Bid.

III.F.2.2.2.4. Interval Revenue.

III.F.2.2.2.5. Credit Calculation for Generator Assets and Demand Response Resources.

III.F.2.2.2.6. [Reserved.]

III.F.2.2.2.7. Credit Calculation for Binary Storage DARDs.

III.F.2.2.2.8. Resources with Commitment in the Day-Ahead Energy Market.

- III.F.2.2.3. Real-Time Dispatch NCPC Credits for Generator Assets and Demand Response Resources.
  - III.F.2.2.3.1. Settlement Period.
  - III.F.2.2.3.2. Eligible Quantity.
  - III.F.2.2.3.3. Interval Cost.
  - III.F.2.2.3.4. Interval Revenue.
  - III.F.2.2.3.5. Credit Calculation.
- III.F.2.2.4. Real-Time Dispatch NCPC Credits for Storage DARDs.
  - III.F.2.2.4.1. Settlement Period.
  - III.F.2.2.4.2. Eligible Quantity.
  - III.F.2.2.4.3. Interval Cost.
  - III.F.2.2.4.4. Interval Bid.
  - III.F.2.2.4.5. Credit Calculation.
- III.F.2.2.5. Real-Time Dispatch Lost Opportunity Cost NCPC Credits.
  - III.F.2.2.5.1. Maximum Net Revenue or Maximum Net Benefit.
  - III.F.2.2.5.2. Actual Net Revenue or Actual Net Benefit.
  - III.F.2.2.5.3. Credit Calculation.
- III.F.2.3. Special Case NCPC Credit Calculations
  - III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits
  - III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits
  - III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)
  - III.F.2.3.4. [Reserved.]
  - III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits
  - III.F.2.3.6. Cancelled Start NCPC Credits
  - III.F.2.3.7. Hourly Shortfall NCPC Credits
  - III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability
  - III.F.2.3.9. Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured for Reliability and Demand Response Resources Postured for Reliability
  - III.F.2.3.10. Rapid Response Pricing Opportunity Cost NCPC Credits Resulting from Commitment of Rapid Response Pricing Assets

III.F.2.4. Apportionment of NCPC Credits

III.F.2.5. Credit Designation for Purposes of NCPC Cost Allocation

III.F.3. Charges for NCPC

III.F.3.1 Cost Allocation

III.F.3.1.1 Day-Ahead Energy Market NCPC Cost Allocation

III.F.3.1.2 Real-Time Energy Market NCPC Cost Allocation

III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation

III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits

III.F.3.3 Local Second Contingency Protection Resource NCPC Charges

III.F.4. NCPC Reporting

## NCPC ACCOUNTING

### III.F.1. General.

For purposes of NCPC calculations:

- a. Effective Offers.** An Effective Offer for a Resource is (1) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to commit the Resource and (2) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to dispatch the Resource at a Desired Dispatch Point above its Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit, and is subject to the following conditions:
- i. The Effective Offer used in making the decision to commit the Resource establishes the parameters used for NCPC calculations, including the quantity and price pairs for output, demand reduction, or consumption up to the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit; the Start-Up Fee, No-Load Fee, or Interruption Cost; and the operating limits.
  - ii. In the event the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit is increased after the decision to commit the Resource, the energy price parameter for output, demand reduction, or consumption at the Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit used in making the decision to commit the Resource will be applied as the energy price parameter for additional output, demand reduction, or consumption up to the increased Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit.
  - iii. In the event a Minimum Generation Emergency is declared, the Economic Minimum Limit will be replaced with the Emergency Minimum Limit for purposes of determining the energy price parameter of the Effective Offer.
  - iv. The Effective Offer takes account of mitigation applied to the Supply Offer, whether performed prior to or after the commitment or dispatch decision is made.
  - v. The Effective Offer takes account of a reduction in the energy price parameter, the Start-Up Fee, the No-Load Fee, or the Interruption Cost in a Supply Offer or Demand Reduction Offer; or an increase in the energy price parameter of a Demand Bid that is made prior to the end of the Resource's Commitment Period.
  - vi. In the event the ISO approves the Resource's synchronization to the system as a Pool-Scheduled Resource earlier than its scheduled time, the Effective Offer takes account of the

lesser of the energy price parameter, the Start-Up Fee and the No-Load Fee in place for the scheduled Commitment Period or the actual early release-for-dispatch time.

~~vii.~~ vii. A Resource that is online providing synchronous condensing is considered to be in a hot temperature state for the purpose of determining the Start-Up Fee for the Effective Offer when the Resource is requested to switch from synchronous condensing to provide energy.

~~viii.~~ viii. The Effective Offer takes account of cost verification performed under Section III.1.9.1.

~~ix.~~ ix. The energy price parameter of the Effective Offer for a Demand Response Resource is the energy price parameter submitted in the Demand Reduction Offer, even where the Demand Reduction Threshold Price is used to clear the market pursuant to Section III.1.10.1A(e)(ii).

**b. Treatment of Self-Schedules.**

- i. In the Day-Ahead Energy Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to \$0, a No-Load Fee equal to \$0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to the minimum of the Energy Offer Floor and the Day-Ahead Price; or, in the case of a Storage DARD, is treated as having a Demand Bid with an energy price parameter for consumption up to its Minimum Consumption Limit equal to the maximum of the ~~Energy Offer Cap~~ Demand Bid Cap and the Day-Ahead Price. Any amounts (MW) offered or bid above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid.
- ii. In the Real-Time Energy Market, a Resource that is committed as a Self-Schedule is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to \$0, a No-Load Fee equal to \$0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to \$0/MWh; or (ii) as having a Demand Bid for consumption up to the Minimum Consumption Limit at the ~~Energy Offer Cap~~ Demand Bid Cap. Any amounts (MW) offered above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid. For any hour for which a Resource is dispatched pursuant to Section III.1.10.9(f), the Resource is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to \$0, a No-Load Fee equal to \$0, and an energy price parameter for output up to the requested amount at the Energy Offer Floor; or (ii) as having a Demand Bid with an energy price parameter for consumption up to the requested amount at the Energy Offer Cap.

- iii. If the Resource's Supply Offer contains a Self-Schedule for fewer contiguous hours than its Minimum Run Time, the minimum number of additional hours required to satisfy the Resource's Minimum Run Time will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market. If the Resource is committed for one or more hours immediately prior to and contiguous with the Self-Schedule, the hours of that prior Commitment Period will be counted toward satisfying the Resource's Minimum Run Time before hours subsequent to the Self-Schedule are counted. If the Resource's Supply Offer contains two Self-Schedules separated by less than the Resource's Minimum Down Time, the hours between the two Self-Schedules will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market.
- c. **Sub-Hourly Intervals.** If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.
- d. **Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Minimum Run Time or Minimum Reduction Time Carries Into Second Operating Day.** If a Resource that is committed in either (i) the Day-Ahead Energy Market, or (ii) the Reserve Adequacy Analysis prior to the start of the Operating Day must continue to operate across an Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for hour ending 24 of the Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day. If a Resource that is committed during the Operating Day must continue to operate across the Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the second Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day.
- e. **Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Committed Prior to Day-Ahead Energy Market.** If a Resource is committed for an Operating Day prior to the Day-Ahead Energy Market, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the Operating Day at the time of the commitment is used to establish the Effective Offer for the period of the commitment.
- f. **Eligibility for NCPC Credits When Performing Audits or Facility and Equipment Testing.**

The Real-Time NCPC Credit calculation for a Resource performing an audit uses the Start-Up Fee, No-Load Fee, Interruption Cost, Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction in the Effective Offer applicable to the Commitment Period during which the audit is conducted, and does not take account of any increases to the Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction that take place in the course of the audit.

Market Participants are not eligible for NCPC Credits when conducting audits or Facility and Equipment Testing under the following conditions:

- i. When a Market Participant requests that some hours of the commitment of a Pool-Scheduled Resource be used to satisfy an audit, and the Market Participant has changed the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit for those hours for the purpose of conducting the audit, the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- ii. When a Market Participant Self-Schedules a Resource to perform the audit, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the Self-Schedule and is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- iii. When a Market Participant requests that an audit be performed that requires the ISO to dispatch the Resource for the audit without advance notice to the Market Participant, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment or Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- iv. When an ISO-Initiated Claimed Capability Audit is performed pursuant to III.1.5.1.4, the Market Participant is not eligible for Real-Time Commitment NCPC Credits or Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted if both of the following are true:
  1. the Resource had a summer or winter Seasonal Claimed Capability or Seasonal DR Audit value equal to 0 MW at the beginning of the current Capability Demonstration Year, and
  2. the ISO Initiated Claimed Capability Audit is the first Claimed Capability Audit that the Resource performs during that Capability Demonstration Year.

- v. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Pool-Scheduled Resource, the Economic Minimum Limit (or Minimum Consumption Limit for a Binary Storage DARD) in place at the time of the commitment decision is used for calculating Real-Time Commitment NCPC Credits and the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.
- vi. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Resource that Self-Scheduled, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment and is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.
- g. Coordinated External Transactions are Not Eligible for NCPC and are excluded from NCPC Charges.** Notwithstanding anything to the contrary in this Appendix F, Market Participants are not eligible to receive NCPC Credits for Coordinated External Transactions purchases or sales and shall be excluded from all NCPC Charge calculations under this Appendix F.
- h. Demand Response Resource Credit Calculations.** Where indicated in Section III.F.2, the costs and revenues for a Demand Response Resource, other than those associated with Net Supply or Interruption Costs, are increased by average avoided peak distribution losses.
- i. Following Dispatch Instructions.**
  - i. For the purpose of allocating NCPC costs, a Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit greater 50 MW is considered to be following a dispatch instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 10% above its Desired Dispatch Point and not less than 10% below its Desired Dispatch Point for each interval in the hour. A Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit less than or equal to 50 MW is considered to be following a Dispatch Instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 5 MW above its Desired Dispatch Point and is not less than 5 MW below its Desired Dispatch Point for each interval in the hour. If the Resource violates this criterion in any interval during the hour, the Resource is considered to be not following Dispatch Instructions for the entire hour.



- ii. DNE Dispatchable Generators are considered to be following Dispatch Instructions if the actual output of the DNE Dispatchable Generator is at or below its Do Not Exceed Dispatch Point.

### **III.F.2. NCPC Credits**

#### **III.F.2.1 Day-Ahead Energy Market NCPC Credits**

**III.F.2.1.1. Eligibility for Credit.** A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a Storage DARD with a Demand Bid that clear the Day-Ahead Energy Market in an hour is eligible for Day-Ahead Energy Market NCPC Credits for the hour.

**III.F.2.1.2. Settlement Period.** For a Generator Asset, a Demand Response Resource, or a Storage DARD, for purposes of calculating Day-Ahead Energy Market NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day for which a Resource has cleared in the Day-Ahead Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator or to or from a Fast Start Demand Response Resource, or any time a DNE Dispatchable Generator's operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation.

**III.F.2.1.3. Eligible Quantity.** For a Generator Asset, Demand Response Resource, or Storage DARD, the eligible quantity of energy is the amount of energy the Resource clears in the Day-Ahead Energy Market for each hour of the settlement period.

**III.F.2.1.3A Hourly Bid.** For a Storage DARD, the hourly bid is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each hour of the settlement period.

#### **III.F.2.1.4 Hourly Cost.**

- (a) For a Generator Asset, the hourly cost is equal to the energy price parameter for the eligible quantity, the Start-Up Fee and the No-Load Fee as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.
- (b) For a Demand Response Resource, the hourly cost is equal to the energy price parameter for the eligible quantity and the Interruption Cost as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.

(c) For a Storage DARD, the hourly cost is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity.

**III.F.2.1.4.1** For a Generator Asset or a Demand Response Resource, the Start-Up Fee or Interruption Cost is apportioned equally over the hours from the time the Resource is scheduled to begin its commitment through the end of the Commitment Period during which the Minimum Run Time or Minimum Reduction Time is scheduled to expire.

**III.F.2.1.4.2** For a Generator Asset or a Demand Response Resource, when the period of hours over which the Start-Up Fee or Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee or Interruption Cost.

**III.F.2.1.5 Hourly Revenue.** For a Generator Asset or a Demand Response Resource, the hourly revenue is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity for the Resource.

**III.F.2.1.6 General Credit Calculation.** Except as provided in Section III.F.2.1.7 below, the Day-Ahead Energy Market NCPC Credit for a Resource, adjusted as described in III.F.1(h), is equal to:

- (a) For a Generator Asset or a Demand Response Resource: the greater of (i) zero, and; (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly revenue for the Resource in all hours of the settlement period, where the costs and revenues of a Demand Response Resource, other than those associated with Interruption Costs, are increased by average avoided peak distribution losses; and
- (b) For a Binary Storage DARD: the greater of (i) zero and (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly bids in all hours of the settlement period.

**III.F.2.1.7 Credit Calculation for Fast Start Generators, Flexible DNE Dispatchable Generators, Fast Start Demand Response Resources and Binary Storage DARDs Based on Daily Starts, and for Continuous Storage Generator Assets and Continuous Storage DARDs.** If either (1) the number of daily starts for a Fast Start Generator, Flexible DNE Dispatchable Generator, Fast Start Demand Response Resource or Binary Storage DARD is less than the resource's Maximum Number of Daily Starts, or (2) the resource is a Continuous Storage Generator Asset or a Continuous Storage DARD,

then the resource's Day-Ahead Energy Market NCPC Credit, adjusted as described in III.F.1(h), is calculated as follows:

- (a) For a Fast Start Generator, a Continuous Storage Generator Asset, a Flexible DNE Dispatchable Generator or a Fast Start Demand Response Resource, the Day-Ahead Energy Market NCPC Credit is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for the Resource in an hour minus the hourly revenue for the Resource in that hour.
- (b) For a Storage DARD, the Day-Ahead Energy Market NCPC Credit is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the total hourly cost for the Resource in an hour minus the total hourly bid for the Resource in that hour.

**III.F.2.2 Real-Time Energy Market NCPC Credits.** Real-Time Energy Market NCPC Credits include a Real-Time Commitment NCPC Credit, a Real-Time Dispatch NCPC Credit and a Real-Time Dispatch Lost Opportunity Cost NCPC Credit. For purposes of this Section III.F.2.2, unless otherwise expressly stated, costs and revenues shall be calculated at a five minute interval.

**III.F.2.2.1 Eligibility for Credit.**

- (a) Commitment Credits – The following Resources are eligible for Real-Time Commitment NCPC Credits for some or all intervals of the hour: (i) a Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market and that has been committed by the ISO; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; or (iii) a Binary Storage DARD with a Demand Bid that has been submitted in the Real-Time Energy Market and that has been committed by the ISO.
- (b) Dispatch Credits – The following Resources are eligible for Real-Time Dispatch NCPC Credits for some or all intervals of the hour: (i) a Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; (iii) a Storage DARD with a Demand Bid that has been submitted in the Real-Time Energy Market; or (iv) a Storage DARD that has been Postured to increase its consumption. The Real-Time Dispatch NCPC Credit shall be zero, however, if the Generator Asset has provided Regulation during the interval.
- (c) Dispatch Lost Opportunity Cost Credits – A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a Dispatchable Asset Related Demand with a Demand Bid that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Real-Time Dispatch Lost Opportunity Cost NCPC Credit; provided, however,

that such credit shall be zero if the Generator Asset, Demand Response Resource, or Dispatchable Asset Related Demand has been Postured or has provided Regulation during the interval.

### **III.F.2.2.2 Real-Time Commitment NCPC Credits**

#### **III.F.2.2.2.1 Settlement Period.**

- (a) For Generator Assets, Demand Response Resources, and Binary Storage DARDs, for purposes of calculating Real-Time Commitment NCPC Credits, a settlement period is a period of one or more contiguous intervals in an Operating Day during which a Resource is operating pursuant to one or more commitments in the Day-Ahead Energy Market or Real-Time Energy Market.
- (b) For Generator Assets and Demand Response Resources, a new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.
- (c) For Generator Assets and Binary Storage DARDs, in the event of an interruption in operation of a Resource, operation will be considered contiguous if the Resource returns to operation in accordance with the original commitment issued prior to the interruption.

#### **III.F.2.2.2.2 Eligible Quantity.**

**III.F.2.2.2.2.A** For a Binary Storage DARD, the eligible quantity for each interval is the amount of energy equal to the lesser of its Economic Dispatch Point for that interval and its Metered Quantity For Settlement for the interval.

#### **III.F.2.2.2.2.1.**

- (a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy equal to the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval; provided however, that during contiguous pricing intervals in which the Generator Asset's Economic Dispatch Point is higher than it would otherwise be as a result of an offered ramp rate limitation, then the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit

is the amount of energy for the interval equal to the lesser of: (a) the Generator Asset's Metered Quantity For Settlement; and (b) the greater of: (i) the Generator Asset's expected output level had it reduced its output per its offered ramp rate during the relevant intervals as instructed by the ISO, and (ii) the output level to which the Generator Asset would have been dispatched absent the offered ramp rate limitation.

- (b) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval, except that Metered Quantity For Settlement is used as the eligible quantity (i) when the Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) when the Resource is ramping from an offline state to be released for dispatch or (iii) after the Resource has been released for shutdown.

**III.F.2.2.2.2.**

- (a) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and its Economic Dispatch Point for the interval; provided however, that during contiguous pricing intervals in which the Demand Response Resource's Economic Dispatch Point is higher than it would otherwise be as a result of an offered ramp rate limitation, then the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy for the interval equal to the lesser of: (a) the Demand Response Resource's Metered Quantity For Settlement; and (b) the greater of: (i) the Demand Response Resource's expected demand reduction had it provided the reduction per its offered ramp rate during the relevant intervals as instructed by the ISO, and (ii) the demand reduction level at which the Demand Response Resource would have been dispatched absent the offered ramp rate limitation.
- (b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is equal to the eligible quantity used to determine interval costs pursuant to (a) above, except that the eligible quantity shall be the Metered Quantity For Settlement if any of the following are true: (i) the Demand Response Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time have

not concluded, or (iii) the Demand Response Resource has received an instruction to stop reducing demand.

#### **III.F.2.2.2.3. Interval Cost.**

- (a) The interval cost for a Generator Asset is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Start-Up Fee and No-Load Fee as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1, III.F.2.2.2.3.2, and III.F.2.2.2.3.3.
- (b) The interval cost for a Demand Response Resource is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Interruption Cost as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1 and III.F.2.2.2.3.2, provided that costs shall be set to \$0 for the interval when there is a negative demand reduction.
- (c) The interval cost for a Binary Storage DARD is the Real-Time Price for the interval multiplied by the eligible quantity. The interval cost is reduced by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval cost is also reduced by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5.

#### **III.F.2.2.2.3.1**

- (a) For a Generator Asset, the energy cost for an interval excludes the cost of (a) energy produced when the Resource is ramping from an offline state to be released for dispatch and (b) energy produced after the Resource has been released for shutdown.
- (b) For a Demand Response Resource, the energy cost for an interval excludes the cost of (a) energy produced prior to the conclusion of the Demand Response Resource Start-Up Time and (b) energy produced after the Demand Response Resource has received an instruction to stop reducing demand.

#### **III.F.2.2.2.3.2**

- (a) For a Generator Asset, the Start-Up Fee is apportioned equally over the intervals from the time the Generator Asset is released for dispatch through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire, subject to the following conditions:

- (i) The Start-Up Fee is reduced in proportion to the number of minutes after 30 the Generator Asset is released for dispatch (measured from the time the Generator Asset was scheduled to be released for dispatch), divided by the time from when the Generator Asset was scheduled to be released for dispatch through the end of the Commitment Period during which the Minimum Run Time was scheduled to expire.
  - (ii) The Start-Up Fee is excluded from the interval cost calculation if the Generator Asset is synchronized to the system prior to its scheduled synchronization time without the ISO's approval of the Generator Asset's synchronization as a Pool-Scheduled Resource.
  - (iii) The portion of the Start-Up Fee apportioned to any interval during which the Generator Asset is not online because the Generator Asset has tripped is excluded from the interval cost calculation, except in the event the Generator Asset is not online due to a trip that results from equipment failure involving equipment located on the electric network beyond the low voltage terminals of the Generator Asset's step-up transformer. It is the responsibility of the Lead Market Participant for the Generator Asset to inform the ISO at [xtrip@iso-ne.com](mailto:xtrip@iso-ne.com) within 30 days that the trip was the result of such a transmission-related event.
  - (iv) The Start-Up Fee is not reduced when the Generator Asset has shutdown with the ISO's approval prior to the end of its Commitment Period.
  - (v) The additional Start-Up Fee for a Generator Asset requested to re-start following a trip is apportioned equally over the remaining intervals of the Commitment Period when the ISO requests a Generator Asset to re-start to complete its Commitment Period.
  - (vi) When the period of intervals over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.
- (b) For a Demand Response Resource, the Interruption Cost is apportioned equally over the intervals from the time the Demand Response Resource Start-Up Time concludes through the end of the Commitment Period during which the Minimum Reduction Time is scheduled to expire, subject to the following conditions:
- (i) The Interruption Cost is reduced in proportion to the number of minutes after 30 the Demand Response Resource begins to provide a demand reduction (measured from the conclusion of the Demand Response Resource Start-Up Time), divided by the time from the conclusion of the Demand Response Resource Start-Up Time through the end of the Commitment Period during which the Minimum Reduction Time was scheduled to expire.

- (ii) The portion of the Interruption Cost apportioned to any interval during which the Demand Response Resource is not providing a demand reduction because the Demand Response Resource has become unavailable to provide a reduction is excluded from the interval cost calculation.
- (iii) The Interruption Cost is not reduced when the Demand Response Resource has stopped reducing demand with the ISO's approval prior to the end of its Commitment Period. When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.
- (iv) When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.

**III.F.2.2.2.3.3.** For a Generator Asset for each hour, the No-Load Fee is equally apportioned to each interval in the hour during the period when the Generator Asset is online following its release for dispatch and prior to its release for shutdown. The No-Load Fee is pro-rated for the hour during which the Generator Asset is released for dispatch, the hour during which the Generator Asset is released for shutdown, and any other hour during which the Generator Asset operates for less than 60 minutes.

**III.F.2.2.2.3.A Interval Bid.** The interval bid for a Binary Storage DARD is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each interval of the settlement period.

**III.F.2.2.2.4 Interval Revenue.** The interval revenue for a Generator Asset or Demand Response Resource is equal to the Real-Time Price for each interval of the settlement period multiplied by the eligible quantity for the interval. The revenue for an interval is increased by the amount by which the interval revenues in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.4 exceed the interval costs in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.3. The interval revenue is increased by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval revenue is also increased by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5. The revenues when the Generator Asset is ramping from an offline state to be released for



dispatch, or during the Demand Response Resource Start-Up Time, are apportioned equally to the intervals of the Minimum Run Time or Minimum Reduction Time.

**III.F.2.2.2.4.1.** For a Generator Asset, revenues for output up to the Resource's Economic Minimum Limit in a Self-Scheduled interval, calculated as the Real-Time Price multiplied by the output, are excluded from the revenue for the Real-Time Commitment NCPC Credit calculation.

**III.F.2.2.2.4.2.** For a Demand Response Resource, revenues shall be set to \$0 for the interval when the Locational Marginal Price is positive and there is a negative demand reduction.

**III.F.2.2.2.5 Credit Calculation for Generator Assets and Demand Response Resources.** The Real-Time Commitment NCPC Credit for a Generator Asset or a Demand Response Resource, adjusted as described in III.F.1(h) is equal to:

- (a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval revenue for the Resource for the period, plus,
- (b) For each remaining interval of the settlement period following the completion of the Minimum Run Time or Minimum Reduction Time, the greater of ((i) zero, and; (ii) the maximum potential net revenues for the Resource in the period) minus the actual net revenues for the Resource in the period, where
  - (i) The maximum potential net revenue is the maximum accumulated net interval revenue for operating and then shutting down (or, for a Demand Response Resource, reducing demand and then ceasing to reduce demand) during the period.
  - (ii) The actual net revenue is the accumulated net interval revenue over the period.
  - (iii) The net interval revenue is the interval revenues minus interval costs in the period.

**III.F.2.2.2.6. [Reserved.]**

**III.F.2.2.2.7 Credit Calculation for Binary Storage DARDs.** The Real-Time Commitment NCPC Credit for a Binary Storage DARD is equal to:

(a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval bid for the Resource for the period,

plus,

(b) For each remaining interval of the settlement period following the completion of the Minimum Run Time, the greater of ((i) zero, and; (ii) the maximum potential net benefit for the Resource in the period) minus the actual net benefit for the Resource in the period, where

(i) The maximum potential net benefit is the maximum accumulated net interval benefit for operating and then shutting down during the period.

(ii) The actual net benefit is the accumulated net interval benefit over the period.

(iii) The net interval benefit is the interval bid minus interval cost in the period.

**III.F.2.2.2.8 Resources with Commitment in the Day-Ahead Energy Market (other than Fast Start Generators, Fast Start Demand Response Resources, and Binary Storage DARDs).**

(a) For purposes of calculating the interval cost under Section III.F.2.2.2.3, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or Binary Storage DARD) has a commitment in the Day-Ahead Energy Market, the Start-Up Fee, No-Load Fee, Interruption Cost and energy price parameter for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to \$0 for the hour. The Start-Up Fee shall not be set to \$0 in the case when a Resource re-starts at ISO request following a trip.

(b) For purposes of calculating the interval revenue under Section III.F.2.2.2.4, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or Binary Storage DARD) has a commitment in the Day-Ahead Energy Market, the revenue for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to \$0 for the hour if such revenue is less than \$0.

(c) Notwithstanding anything to the contrary in this Section III.F.2.2.2, a Generator Asset that cleared in the Day-Ahead Energy Market and performs an audit scheduled by the ISO pursuant to Section III.1.5.2(f) during all or part of its Day-Ahead schedule on a higher-priced fuel than that which formed the basis of the Generator Asset's Supply Offer in the Day-Ahead Energy Market shall receive additional compensation equal to:

i. For the MW quantity equal to the lesser of the Generator Asset's actual metered output and Economic Dispatch Point, the difference between 1) the incremental energy audit costs based on

- the Supply Offer using the fuel on which the audit was performed and 2) amounts calculated for that same operation as reflected in the greater of the Day-Ahead Supply Offer and the cost-based Reference Levels calculated using the fuel on which the Day-Ahead Supply Offer was based; and
- ii. The difference between the No-Load Fee based on the Supply Offer using the fuel on which the audit was performed and the No-Load Fee for that same operation as reflected in the Day-Ahead Supply Offer; and
  - iii. Any additional Start-Up Fees incurred as a result of performing the audit.

**III.F.2.2.3. Real-Time Dispatch NCPC Credits for Generator Assets and Demand Response Resources.**

**III.F.2.2.3.1 Settlement Period.**

- (a) Except as provided in Section III.F.2.2.3.1(b), for Generator Assets and Demand Response Resources, for purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement for a Resource are each greater than its Economic Dispatch Point, excluding any period of time when:
  - i. For a Generator Asset, the generator is ramping from an offline state to be released for dispatch, and after the generator has been released for shutdown, or
  - ii. For a Demand Response Resource, prior to the conclusion of the Demand Response Start-Up Time and after the Demand Response Resource has received a Dispatch Instruction to stop reducing demand.
- (b) For a Continuous Storage Generator Asset associated with an ATRR that has provided Regulation during the interval, a settlement period is an interval when the Desired Dispatch Point is greater than the Economic Dispatch Point.

**III.F.2.2.3.2. Eligible Quantity.**

**III.F.2.2.3.2.1.**

- (a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Generator Asset's Economic Dispatch Point for the interval subtracted from the lesser of the Generator Asset's Metered Quantity For Settlement or Desired Dispatch Point for the interval, unless a Continuous Storage Generator Asset is associated with an ATRR that has provided Regulation during the interval, in which case the eligible quantity is the

Generator Asset's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

- (b) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Demand Response Resource's Economic Dispatch Point for the interval subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement and its Desired Dispatch Point for the interval.

#### **III.F.2.2.3.2.2.**

- (a) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit is the Generator Asset's Metered Quantity For Settlement for the interval minus the Generator Asset's Economic Dispatch Point, except that the Generator Asset's Economic Dispatch Point subtracted from the lesser of the Generator Asset's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval. Notwithstanding the foregoing, if a Continuous Storage Generator Asset is associated with an ATRR that has provided Regulation during the interval, the eligible quantity is the Generator Asset's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.
- (b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit equals the Demand Response Resource's Metered Quantity For Settlement for the interval minus the Demand Response Resource's Economic Dispatch Point, except that the Demand Response Resource's Economic Dispatch Point subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval.

**III.F.2.2.3.3 Interval Cost.** For a Generator Asset or a Demand Response Resource, the interval cost is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer and does not include the Start-Up Fee, the No-Load Fee, or the Interruption Cost.

**III.F.2.2.3.4 Interval Revenue.** For a Generator Asset or a Demand Response Resource, the interval revenue is equal to the Real-Time Price multiplied by the eligible quantity.

**III.F.2.2.3.5. Credit Calculation.** For a Generator Asset or a Demand Response Resource, the Real-Time Dispatch NCPC Credit in an interval is equal to the greater of (i) zero and (ii) the interval cost minus the interval revenue for the Resource, adjusted as described in III.F.1(h).

#### **III.F.2.2.4 Real-Time Dispatch NCPC Credits for Storage DARDs**

**III.F.2.2.4.1 Settlement Period.** For purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement are each greater than the Storage DARD's Economic Dispatch Point, unless a Continuous Storage DARD is associated with an ATRR that has provided Regulation during the interval, in which case a settlement period is an interval when the Desired Dispatch Point is greater than the Economic Dispatch Point.

**III.F.2.2.4.2 Eligible Quantity.** The eligible quantity of energy is equal to the greater of (i) zero and (ii) the Storage DARD's Economic Dispatch Point for the interval subtracted from the lesser of the Storage DARD's Metered Quantity For Settlement or Desired Dispatch Point for the interval, unless a Continuous Storage DARD is associated with an ATRR that has provided Regulation during the interval, in which case the eligible quantity is the DARD's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

**III.F.2.2.4.3 Interval Cost.** The interval cost is the Real-Time Price for the interval multiplied by the eligible quantity.

**III.F.2.2.4.4 Interval Bid.** The interval bid is equal to the energy price parameter for the eligible quantity as reflected in the Demand Bid for each interval of the settlement period.

**III.F.2.2.4.5 Credit Calculation.** The Real-Time Dispatch NCPC Credit for an eligible Storage DARD in an interval is equal to the greater of: (i) zero, and; (ii) the interval cost minus the interval bid in that interval.

#### **III.F.2.2.5. Real-Time Dispatch Lost Opportunity Cost NCPC Credits**

##### **III.F.2.2.5.1. Maximum Net Revenue or Maximum Net Benefit.**

(a) For a Generator Asset or a Demand Response Resource, the maximum net revenue during the interval is the Resource's energy revenue at the Economic Dispatch Point, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point, as described in III.F.1(h).

- (b) For a Dispatchable Asset Related Demand, the maximum net benefit during the interval is the Resource's energy price parameter for the Economic Dispatch Point as reflected in the Demand Bid, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point.

**III.F.2.2.5.2. Actual Net Revenue or Actual Net Benefit.**

- (a) The actual net revenue for a Generator Asset or Demand Response Resource shall be the sum, adjusted as described in III.F.1(h), of the following two values:
  - (i) for a Continuous Storage Generator Asset associated with an ATRR that has provided Regulation during the interval, the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity; otherwise, the greater of: (1) the energy revenue at the Metered Quantity For Settlement minus the offered energy cost for that quantity and (2) the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity; and
  - (ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.
- (b) The actual net benefit for a Dispatchable Asset Related Demand shall be the sum of the following two values:
  - (i) for a Continuous Storage DARD associated with an ATRR that has provided Regulation during the interval, the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity; otherwise, the greater of: (1) the energy price parameter for the Metered Quantity For Settlement as reflected in the Demand Bid minus the offered energy cost for that quantity and (2) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity; and
  - (ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.

**III.F.2.2.5.3. Credit Calculation.** For a Generator Asset, a Demand Response Resource, or a Dispatchable Asset Related Demand, the Real-Time Dispatch Lost Opportunity Cost NCPC Credit is equal to the greater of: (i) zero; and (ii) the Resource's maximum net revenue or benefit for the interval less its actual net revenue or benefit for the interval.

The Dispatch Lost Opportunity Cost NCPC Credit for a Resource for an interval shall be reduced by the amount of any Rapid Response Pricing Opportunity Cost NCPC Credits for which the Resource is eligible for that interval, but shall be no less than zero.

### **III.F.2.3. Special Case NCPC Credit Calculations**

#### **III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits**

**III.F.2.3.1.1. Eligibility for Credit.** All Market Participants with pool-scheduled External Transaction imports or Increment Offers at an External Node are eligible for Day-Ahead External Transaction Import and Increment Offer NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

**III.F.2.3.1.2. Hourly Offer.** The Day-Ahead offer for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the offer price.

**III.F.2.3.1.3. Hourly Revenue.** The Day-Ahead revenue for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price.

**III.F.2.3.1.4. Credit Calculation.** A Day-Ahead External Transaction Import and Increment Offer NCPC Credit for an External Transaction import or Increment Offer, for an hour, is equal to any portion of the Day-Ahead offer in excess of the Day-Ahead revenue for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction import or Increment Offer for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction export or Decrement Bid for the same External Node and hour, the Day-Ahead External Transaction Import and Increment Offer NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction import or Increment Offer at the External Node for the hour that is not offset by the amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour. If multiple External Transaction imports or Increment Offers at an External Node are eligible for a Day-Ahead External Transaction Import and Increment Offer NCPC Credit, then for purposes of the offsetting

determination in the prior sentence External Transaction imports and Increment Offers will be offset in order from the highest to the lowest-priced transactions or offers.

#### **III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits**

**III.F.2.3.2.1. Eligibility for Credit.** All Market Participants with pool-scheduled External Transaction exports or Decrement Bids at an External Node are eligible for Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

**III.F.2.3.2.2. Hourly Bid.** The Day-Ahead bid for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the bid price.

**III.F.2.3.2.3. Hourly Cost.** The Day-Ahead cost for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price at the External Node.

**III.F.2.3.2.4. Credit Calculation.** A Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for an External Transaction export or Decrement Bid, for an hour, is equal to any portion of the Day-Ahead hourly cost in excess of its Day-Ahead hourly bid for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction export or Decrement Bid for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction import or Increment Offer for the same External Node and hour, the Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour that is not offset by the amount (MW) of the total cleared External Transaction import or Increment Offer at the External Node for the hour. If multiple External Transaction exports or Decrement Bids at an External Node are eligible for a Day-Ahead External Transaction Export and Decrement Bid NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction exports and Decrement Bids will be offset in order from the lowest to the highest-priced transactions or bids.

#### **III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)**



**III.F.2.3.3.1. Eligibility for Credit.** All Market Participants that submit pool-scheduled External Transactions (import or export) are eligible for Real-Time External Transaction NCPC Credits, with the exception of External Transactions to wheel energy through the New England Control Area.

**III.F.2.3.3.2. Eligible Quantity.**

- (a) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that either (i) did not clear in the Day-Ahead Energy Market, or (ii) cleared in the Day-Ahead Energy Market and the price was subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction.
- (b) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that cleared in the Day-Ahead Energy Market and the price was not subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction in excess of the cleared Day-Ahead scheduled transaction amount.

**III.F.2.3.3.3. Hourly Offer.** The hourly offer for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval offer, which is calculated by multiplying the eligible quantity by the offer price for the interval.

**III.F.2.3.3.4. Hourly Revenue.** The hourly revenue for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval revenue, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

**III.F.2.3.3.5. Hourly Bid.** The hourly bid for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval bid, which is calculated by multiplying the eligible quantity by the bid price for the interval.

**III.F.2.3.3.6. Hourly Cost.** The Real-Time cost for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval cost, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

**III.F.2.3.3.7. Credit Calculation.** A Real-Time External Transaction NCPC Credit for an External Transaction import for an hour is equal to any portion of the hourly offer in excess of the hourly revenue.

A Real-Time External Transaction NCPC Credit for an External Transaction export for an hour is equal to any portion of the hourly cost in excess of the hourly bid.

**III.F.2.3.4. [Reserved.]**

**III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits**

**III.F.2.3.5.1. Eligibility for Credit.** A Resource that is dispatched as a Synchronous Condenser is eligible for Real-Time Synchronous Condensing NCPC Credits.

**III.F.2.3.5.2. Condensing Offer Amount.** The condensing offer amount for a Resource is equal to the number of hours that the Resource is dispatched as a Synchronous Condenser in an Operating Day multiplied by the hourly price to condense as specified in the Offer Data for the Resource. For a Resource committed from an offline state to provide synchronous condensing, the condensing offer amount includes the condensing start-up fee as specified in the Offer Data for the Resource. In the event an hourly price to condense or condensing start-up fee is not included in the Offer Data for the Resource for the hours that the Resource is dispatched as a Synchronous Condenser, the value for the parameter will be zero.

**III.F.2.3.5.3. Credit Calculation.** The Real-Time Synchronous Condensing NCPC Credit for a Resource for an Operating Day is equal to the condensing offer amount for that Operating Day.

**III.F.2.3.6. Cancelled Start NCPC Credits**

**III.F.2.3.6.1. Eligibility for credit.** A Pool-Scheduled Generator Asset or Demand Response Resource is eligible for a Cancelled Start NCPC Credit if the ISO cancels its commitment of the Pool-Schedule Resource before a Generator Asset is synchronized to the New England Transmission System, or before a Demand Response Resource has completed its Demand Response Resource Notification Time, except that a Market Participant is not eligible for a credit under the following conditions:

- (a) The start is cancelled before the commencement of the Notification Time or the Demand Response Resource Notification Time;
- (b) The Resource's Notification Time or Demand Response Resource Notification Time as reflected in the Effective Offer is equal to or greater than 24 hours;

- (c) The Generator Asset is synchronized to the New England Transmission System for a Self-Schedule within the period of time equal to the lesser of its Minimum Down Time or 10 hours after receiving the ISO cancelled start order; or
- (d) The Generator Asset fails to meet its scheduled synchronization time and the ISO cancelled start order is issued more than two hours after the Resource's scheduled synchronization time.

**III.F.2.3.6.2. Credit Calculation.** The Cancelled Start NCPC Credit for a Resource is equal to the Start-Up Fee or Interruption Cost reflected in the Effective Offer multiplied by the percentage of the Notification Time or Demand Response Resource Notification Time, as reflected in the Effective Offer, that the Resource completed prior to the ISO cancelled start order, where:

- (a) The percentage of Notification Time or Demand Response Notification Time completed is equal to the number of minutes after the start of the Notification Time or Demand Response Notification Time the Resource was cancelled divided by the Notification Time or Demand Response Notification Time, and cannot exceed 100%.

**III.F.2.3.7. Hourly Shortfall NCPC Credits**

**III.F.2.3.7.1. Eligibility for Credit.** A Generator Asset, Demand Response Resource, or Binary Storage DARD that is pool-scheduled in the Day-Ahead Energy Market is eligible for Hourly Shortfall NCPC Credits for an hour if the ISO (1) cancels its commitment of a non-Fast Start Generator, a non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator; or (2) does not dispatch a Fast Start Generator, a Fast Start Demand Response Resource, a Binary Storage DARD, or a Flexible DNE Dispatchable Generator for the hour; and (3) either the Generator Asset or Binary Storage DARD is offline and available for operation and the Generator Asset associated with the DARD is not supplying electricity to the grid, or the Demand Response Resource has not been dispatched and is available for operation; except that (4) a Market Participant is not eligible for a credit under the following conditions:

- (a) The Resource has been Postured for all or part of the hour;
- (b) The Resource is a Limited Energy Resource that has been Postured during a prior hour in the Operating Day; or
- (c) The Resource is an Intermittent Power Resource that is not a DNE Dispatchable Generator.

**III.F.2.3.7.2. Settlement Period.** For purposes of calculating Hourly Shortfall NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is eligible for an Hourly Shortfall NCPC Credit. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.

**III.F.2.3.7.3. Eligible Quantity.** The eligible quantity for each hour of the settlement period is:

- (a) zero for a Fast Start Generator, a Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter, the Start-Up Fee and the No-Load Fee of the Supply Offer, or the total of the energy price parameter and the Interruption Cost of the Demand Reduction Offer, in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market for the hour is greater than the total of the corresponding energy price, Start-Up Fee, No Load Fee, and Interruption Cost parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;
  - i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9(e), the Start-Up Fee, No-Load Fee and energy at the Economic Minimum Limit are equal to \$0, and (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9(f), the Start-Up Fee and No-Load Fee are equal to \$0 and the energy at the requested dispatch level is the Energy Price Floor.
- (b) zero for a Binary Storage DARD in the event the energy price parameter in the Demand Bid in the Real-Time Energy Market for the consumption cleared in the Day-Ahead Energy Market for the hour is less than the energy price parameter in the Demand Bid in the Day-Ahead Energy Market for the hour.
  - i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9 (e), then the energy price at the Minimum Consumption Limit is equal to the ~~Demand Bid Cap~~Energy Offer Cap, and; (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9 (f), then the energy price at the requested dispatch level for Binary Storage DARDs is the ~~Demand Bid Cap~~Energy Offer Cap.
- (c) the Day-Ahead Economic Minimum Limit or Minimum Reduction for a non-Fast Start Generator, non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter of the Supply Offer or Demand Reduction Offer in the Real-Time Energy Market for the amount of energy cleared in the

Day-Ahead Energy Market above the Day-Ahead Economic Minimum Limit or Day-Ahead Minimum Reduction for an hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

and if neither (a) nor (b) nor (c) applies, then;

- (d) the minimum of (i) the amount of energy cleared in the Day-Ahead Energy Market for an hour and (ii) the Resource's Economic Maximum Limit, Maximum Reduction, or a Limited Energy Resource limit imposed for the hour in the Real-Time Energy Market.

**III.F.2.3.7.4. Credit Calculation (for non-Fast Start Generators, non-Fast Start Demand Response Resources, and non-Flexible DNE Dispatchable Generators).** The Hourly Shortfall NCPC Credit for a Resource, other than a Fast Start Generator, a Fast Start Demand Response Resource, a Binary Storage DARD, or a Flexible DNE Dispatchable Generator, adjusted as described in III.F.1(h), is equal to:

- (a) the greater of (i) zero and (ii) the total of (the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the Day-Ahead Economic Minimum Limit for the hour or the Day-Ahead Minimum Reduction for the hour) for all hours of the settlement period,  
plus
- (b) for each hour of the settlement period, for Generator Assets, the greater of (i) zero and (ii) the product of (1) the Real-Time Price minus the Day-Ahead Price for an hour and (2) the eligible quantity minus the Day-Ahead Economic Minimum Limit for the hour; or, for Demand Response Resources, the greater of (i) zero and (ii) the product of (1) the Real Time Price minus the Day-Ahead Price for an hour and (2) the eligible quantity minus the Day-Ahead Minimum Reduction for the hour.

**III.F.2.3.7.5. Credit Calculation (for Fast Start Generators, Fast Start Demand Response Resources and Flexible DNE Dispatchable Generators).** The Hourly Shortfall NCPC Credit for a Fast Start Generator, Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and (ii) the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the eligible quantity for the hour, adjusted as described in III.F.1(h).

**III.F.2.3.7.6 Credit Calculation (for Binary Storage DARDs).** The Hourly Shortfall NCPC Credit for a Binary Storage DARD is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the Day-Ahead Price minus the Real-Time Price for an hour, multiplied by the eligible quantity for the hour.

**III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability**

**III.F.2.3.8.1. Eligibility for Credit.** A Limited Energy Resource is eligible for real-time posturing NCPC credits for any Operating Day during which the Generator Asset has been Postured, when a request to minimize the as-bid production costs of the Generator Asset has been submitted. For purposes of calculating real-time posturing NCPC credits, the Generator Asset is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Generator Asset was Postured, and if not the Generator Asset is treated as a non-Fast Start Generator. If the Generator Asset is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

**III.F.2.3.8.2. Settlement Period.** For purposes of calculating real-time posturing NCPC credits for Limited Energy Resources, a settlement period is the period of one or more contiguous hours from the initiation of Posturing through the end of the Operating Day.

**III.F.2.3.8.3 Resources Sharing a Single Fuel Source.** When Limited Energy Resources that share a fuel source are Postured, for purposes of calculating real-time posturing NCPC credits the energy available to the Postured Generator Assets will be allocated among the Postured Generator Assets sharing the fuel source as indicated by estimates of available energy provided by the Lead Market Participant for each Generator Asset prior to Posturing.

**III.F.2.3.8.4. Estimated Replacement Cost of Energy.** The estimated replacement cost of energy is (i) the average of the Day-Ahead Prices for hours ending 3 through 5 in the subsequent Operating Day for a Generator Asset that is part of an Electric Storage Facility, or (ii) the product of the oil index price multiplied by the oil-fired generator proxy heat rate for fuel oil-fired generating units, or (iii) zero for all other Generator Assets.

For fuel oil-fired generators, the oil index price is the ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation, and the oil-fired generator proxy heat rate is the average of the heat rate at Economic Min and the heat rate at Economic Max, where the heat rate at Economic Min is, for a Generator Asset, the average hourly energy price parameter of the Supply Offer at the Generator Asset's Economic Minimum Limit at the time of the Posturing decision divided by the oil index price, and the heat rate at Economic Max is, for a Generator Asset, the average hourly energy price parameter of the Supply Offer at the Generator Asset's Economic Maximum Limit at the time of the Posturing decision divided by the oil index price.

**III.F.2.3.8.5. Estimated Revenue.** The estimated revenue for a Generator Asset is the optimized energy output multiplied by the Real-Time Price for all hours in the settlement period. The optimized energy output is estimated for each hour by allocating the Postured energy to hours that the Generator Asset would have operated had it not been Postured based on Real-Time Prices in the Operating Day, subject to the following conditions:

- (a) the optimized energy output determination will take account of the Generator Asset's Economic Minimum Limit, and Economic Maximum Limit.
- (b) the optimized energy output determination will take account of the estimated avoided cost of replacing energy that is not allocated to any hour and remains available at the end of the Operating Day.
- (c) for non-Fast Start Generators, the optimized energy output is calculated for the contiguous hours from the time the Generator Asset is Postured until the available energy is depleted.

**III.F.2.3.8.6. Estimated Avoided Replacement Cost.** The estimated avoided replacement cost for an Operating Day is the remaining energy that would have been available at the end of the Operating Day had the Generator Asset operated in accordance with the optimized energy output determination in Section III.F.2.3.8.5, plus any increase in the remaining energy resulting from replenishment during the Operating Day after the Generator Asset is Postured, multiplied by the estimated replacement cost of energy.

**III.F.2.3.8.7. Actual Revenue.** The actual revenue for a Generator Asset is the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the settlement period.

**III.F.2.3.8.8. Actual Avoided Replacement Cost.** The actual avoided replacement cost for an Operating Day is the actual remaining energy at the end of the Operating Day multiplied by the estimated replacement cost of energy.

**III.F.2.3.8.9. Credit Calculation.** The real-time posturing NCPC credit for Limited Energy Resources is equal to the greater of (i) zero and (ii) the estimated revenue plus the estimated avoided replacement cost, minus the actual revenue plus the actual avoided replacement cost.

**III.F.2.3.9. Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured for Reliability and for Demand Response Resources Postured for Reliability**

**III.F.2.3.9.1. Eligibility for Credit.** Generator Assets (other than Limited Energy Resources) and Demand Response Resources are eligible for real-time posturing NCPC credits for the hours during which the Resource has been Postured.

**III.F.2.3.9.2. Settlement Period.** For purposes of calculating real-time posturing NCPC credits, a settlement period is an hour during which the Generator Asset or Demand Response Resource is Postured.

**III.F.2.3.9.3. Offer Used for Estimated Hourly Revenue and Cost.**

- (a) For a Generator Asset, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:
  - (i) Energy Price: the higher of the energy price parameter specified in (1) the Supply Offer for the hour at the time the ISO Postures the Generator Asset, or (2) the Supply Offer for the hour at the start of the hour;
  - (ii) Start-Up Fee and No Load Fee: for Generator Assets Postured offline, the Start-Up Fee and No-Load Fee specified in the Supply Offer for the hour at the time the Generator Asset is Postured;
  - (iii) for Generator Assets Postured to remain online but reduce output, the Start-Up Fee and No-Load Fee are calculated pursuant to Section III.F.2.2.2.3.
- (b) For a Demand Response Resource, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:



- (i) Energy Price: the higher of the energy price parameter specified in (1) the Demand Reduction Offer for the hour at the time the ISO Postures the Resource, or (2) the Demand Reduction Offer for the hour at the start of the hour;
- (ii) Interruption Cost: for a Demand Response Resource Postured to a demand reduction of zero MW, the Interruption Cost specified in the Demand Reduction Offer for the hour at the time the Demand Response Resource is Postured; for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MW, the Interruption Cost is calculated pursuant to Section III.F.2.2.2.3.

#### **III.F.2.3.9.4. Estimated Hourly Revenue.**

- (a) The estimated hourly revenue for a Generator Asset is the optimized energy output multiplied by the Real-Time Price for the hour. The optimized energy output is estimated for each hour by determining where the Generator Asset would have operated had it not been Postured based on Real-Time Prices. The optimized energy output determination will take account of the energy price parameter of the Supply Offer and the Generator Asset's Economic Minimum Limit and Economic Maximum Limit.
- (b) The estimated hourly revenue for a Demand Response Resource is the optimized demand reduction multiplied by the Real-Time Price for the hour, where:
  - (i) The optimized demand reduction is estimated for each hour by determining where the Demand Response Resource would have operated had it not been Postured based on Real-Time Prices. The optimized demand reduction determination will take account of the energy price parameter of the Demand Reduction Offer and the Demand Response Resource's Minimum Reduction and Maximum Reduction.

#### **III.F.2.3.9.5. Estimated Hourly Cost.**

- (a) The estimated hourly cost for a Generator Asset is the energy price parameter of the Supply Offer for the optimized energy output for the hour, plus the Start-Up Fee and the No-Load Fee, subject to the following conditions:
  - (i) For a Fast Start Generator Postured offline, the Start-Up Fee is included in each hour's cost and is not subject to apportionment;
  - (ii) For a non-Fast Start Generator Postured offline, the Start-Up Fee is apportioned, in accordance with Section III.F.2.2.3.2, as if its commitment had not been cancelled.
- (b) The estimated hourly cost for a Demand Response Resource is the energy price parameter of the Demand Reduction Offer for the optimized demand reduction for the hour (where optimized demand

reduction is determined pursuant to Section III.F.2.3.9.4(b)), plus the Interruption Cost, subject to the following conditions:

- (i) For a Fast Start Demand Response Resource Postured to a demand reduction level of zero MW, the Interruption Cost is included in each hour's cost and is not subject to apportionment;
  - (ii) For a non-Fast Start Demand Response Resource Postured to a demand reduction of greater than zero MW, the Interruption Cost is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.
- (c) A Generator Asset is treated as a Fast Start Generator and a Demand Response Resource is treated as a Fast Start Demand Response Resource for purposes of determining the estimated hourly cost only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator or non-Fast Start Demand Response Resource. If at the time the Resource is Postured the Generator Asset is offline, or the Demand Response Resource has not been dispatched, then its designation as a Fast Start Generator or Fast Start Demand Response Resource is determined as of the time of the Posturing decision.

**III.F.2.3.9.6. Actual Hourly Revenue.** The actual hourly revenue for a Generator Asset or a Demand Response Resource is the sum of the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the hour.

**III.F.2.3.9.7. Actual Hourly Cost.**

- (a) The actual hourly cost for a Generator Asset Postured to remain online but reduce output is the sum of the interval cost, which is the energy price parameter of the Supply Offer for the Metered Quantity For Settlement for the interval, plus the Start-Up Fee and No-Load Fee calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Generator Asset Postured offline is zero.
- (b) The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MW is the sum of the interval cost, which is the energy price parameter of the Demand Reduction Offer for the Metered Quantity For Settlement for the interval, plus the Interruption Cost calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to zero MW is zero.

**III.F.2.3.9.8. Credit Calculation.** The real-time posturing NCPC credit for a Generator Asset (other than a Limited Energy Resource) or a Demand Response Resource is equal to the greater of (i) zero and

(ii) the estimated hourly revenue minus the estimated hourly cost, minus the actual hourly revenue minus actual hourly cost, adjusted as described in III.F.1(h).

**III.F.2.3.10. Rapid Response Pricing Opportunity Cost NCPC Credits Resulting from Commitment of Rapid Response Pricing Assets**

**III.F.2.3.10.1. Eligibility for Credit.** During any five-minute pricing interval in which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, any Resource that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Rapid Response Pricing Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Resource is non-dispatchable; the Resource has been Postured or has provided Regulation during the interval; if the Resource is a Settlement Only Resource, or if the Resource is an External Resource or External Transaction.

**III.F.2.3.10.2. Economic Net Revenue or Economic Net Benefit.**

- (a) The economic net revenue for a Generator Asset or Demand Response Resource during the pricing interval is the Resource's optimized feasible energy quantity multiplied by the Real-Time Price, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.
- (b) The economic net benefit for a Dispatchable Asset Related Demand during the pricing interval is the Resource's energy price parameter for its optimized feasible energy quantity as reflected in its Demand Bid, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the optimized feasible energy quantity multiplied by the Real-Time Price.
- (c) The optimized feasible energy and reserve quantities are determined consistent with the Resource's offer or bid parameters, and are the energy and reserve quantities that maximize the Resource's economic net revenue or economic net benefit for the pricing interval, without changing the Resource's commitment status.

**III.F.2.3.10.3. Actual Net Revenue or Actual Net Benefit.**

- (a) Except as provided in Section III.F.2.3.10.3(b), the actual net revenue for a Generator Asset or Demand Response Resource is the greater of: (i) the actual energy quantity supplied during the pricing interval multiplied by the Real-Time Price, plus the actual reserve quantity supplied during the pricing interval multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities; and (ii) the dispatched energy quantity multiplied by the Real-Time Price,

plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

- (b) The actual net revenue for a Generator Asset associated with an ATRR that has provided Regulation during the interval is equal to the dispatched energy quantity multiplied by the Real-Time Price, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.
- (c) Except as provided in Section III.F.2.3.10.3(d), the actual net benefit for a Dispatchable Asset Related Demand is the greater of: (i) the energy price parameter for the actual energy quantity consumed as reflected in the Demand Bid, plus the actual reserve quantity supplied multiplied by the Real-Time Reserve Clearing Price, minus the actual energy quantity consumed multiplied by the Real-Time Price, and (ii) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.
- (d) The actual net revenue for a DARD associated with an ATRR that has provided Regulation during the interval is equal to the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.

**III.F.2.3.10.4. Credit Calculation.** The real-time Rapid Response Pricing Opportunity Cost NCPC Credit for a Resource is equal to the greater of: (i) zero; and (ii) the Resource's economic net revenue or economic net benefit for the interval less its actual net revenue or actual net benefit for the pricing interval.

**III.F.2.4. Apportionment of NCPC Credits.** For purposes of this Section III.F.2.4, any values previously established at the five minute level shall be aggregated to create hourly values.

Each Day-Ahead Energy Market NCPC Credit calculated pursuant to III.F.2.1.6 is apportioned to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue for all hours in the settlement period.

Each Real-Time Commitment NCPC Credit is apportioned as follows: (i) for the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the portion of the Commitment

Period, and (ii) for all remaining intervals of the settlement period, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the period.

Each Hourly Shortfall NCPC Credit for a non-Fast Start Generator, a non-Fast Start Demand Response Resource or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator for energy cleared in the Day-Ahead Energy Market at the Resource's Economic Minimum Limit or Minimum Reduction is apportioned to the hours in which the Real-Time Price exceeds the Day-Ahead Price, for all hours in the settlement period.

The following NCPC credits are assigned to the hours for which the credit was calculated:

- Day-Ahead Energy Market NCPC Credits calculated pursuant to Section III.F.2.1.7.
- Real-Time Dispatch Lost Opportunity Cost NCPC Credits,
- Real-Time Dispatch NCPC Credits for all Resources,
- Day-Ahead External Transaction Import and Increment Offer NCPC Credits,
- Day-Ahead External Transaction Export and Decrement Bid NCPC Credits,
- Real-Time External Transaction NCPC Credits,
- Hourly Shortfall NCPC Credits for Fast Start Generators, Fast Start Demand Response Resources, Binary Storage DARDs and Flexible DNE Dispatchable Generators,
- Hourly Shortfall NCPC Credits for non-Fast Start Generators, non-Fast Start Demand Response Resources, and DNE Dispatchable Generators that are not Flexible DNE Dispatchable Generators for energy cleared in the Day-Ahead Energy Market above the Resource's Economic Minimum Limit or Minimum Reduction, and
- Rapid Response Pricing Opportunity Cost NCPC Credits as described in Section III.F.2.3.10.

**III.F.2.5. NCPC Credit Designation for Purposes of NCPC Cost Allocation.** Each hourly credit for Day-Ahead Energy Market NCPC Credits, Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, Day-Ahead External Transaction Import and Increment Offer NCPC Credits, Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, Real-Time External Transaction NCPC Credits, Hourly Shortfall NCPC Credits, and Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured For Reliability and Demand Response Resources Postured For Reliability, and each daily credit for Real-Time Synchronous Condensing NCPC Credits, Cancelled Start NCPC Credits, Real-

Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability, and Rapid Response Pricing Opportunity Cost NCPC Credit is designated as first contingency, second contingency, voltage (VAR), distribution (SCR), ISO initiated audits and Minimum Generation Emergency consistent with the reason provided by the ISO when issuing a Dispatch Instruction for the Resource. If there is more than one reason provided by the ISO when issuing the Dispatch Instruction, the NCPC Credits are divided equally for purposes of the above designations. With the exception of Day-Ahead External Transaction Import and Increment Offer NCPC Credits and Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, the hourly credits are summed to determine the total credits for each NCPC Charge category for a day.

### **III.F.3. Charges for NCPC**

#### **III.F.3.1. Cost Allocation.**

**III.F.3.1.1 Day-Ahead Energy Market NCPC Cost Allocation.** NCPC costs for the Day-Ahead Energy Market are allocated and charged as follows:

- (a) The total NCPC cost for the Day-Ahead Energy Market associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.
- (b) The total NCPC cost for the Day-Ahead Energy Market for resources designated as Special Constraint Resources in the Day-Ahead Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.
- (c) The total NCPC cost for the Day-Ahead Energy Market for resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.
- (d) For each External Node, the total NCPC cost for Day-Ahead External Transaction Import and Increment Offer NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Load Obligations at the External Node for the hour.
- (e) For each External Node, the total Day-Ahead External Transaction Export and Decrement Bid NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Generation Obligations at the External Node for the hour.

- (f) All remaining NCPC costs for the Day-Ahead Energy Market (except the NCPC costs for Storage DARDs) are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub).
- (g) All remaining NCPC costs for the Day-Ahead Energy Market associated with Storage DARDs are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub) excluding Day-Ahead Load Obligations associated with Storage DARDs.

**III.F.3.1.2. Real-Time Energy Market NCPC Cost Allocation.** NCPC costs for the Real-Time Energy Market are allocated and charged as follows, subject to the conditions in Section III.F.3.1.3:

- (a) The total NCPC cost for the Real-Time Energy Market associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are allocated and charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.
- (b) The total NCPC cost for the Real-Time Energy Market for resources designated as Special Constraint Resources in the Real-Time Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.
- (c) The total ISO initiated audit NCPC cost for resources performing an ISO initiated audit is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.
- (d) The total NCPC cost for resources being Postured in the Real-Time Energy Market is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.
- (e) The total NCPC cost for Rapid Response Pricing Opportunity Cost NCPC Credit during pricing intervals in which one or more Rapid Response Pricing Asset is committed in the Real-Time Energy Market (and not Self-Scheduled) is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.
- (f) The total NCPC cost for the Real-Time Energy Market for resources identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.
- (g) Total Minimum Generation Emergency Credits within a Reliability Region are allocated and charged hourly to Market Participants based on each Market Participant's pro rata share of Real-Time

Generation Obligations, and positive Real-Time Demand Reduction Obligations, excluding that portion of a Market Participant's Real-Time Generation Obligation and Real-Time Demand Reduction Obligation within a Reliability Region that is eligible for a Real-Time Dispatch NCPC Credit pursuant to Section III.F.2.2.3 during a Minimum Generation Emergency.

- (h) The total NCPC cost for Real-Time Dispatch Lost Opportunity Cost NCPC Credits is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.
- (i) All remaining NCPC costs for the Real-Time Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of the absolute values of a Market Participant's (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day (excluding certain positive Real-Time Load Obligation Deviations as described in Section III.F.3.1.3(d)); (ii) generation deviations for Pool-Scheduled Resources not following Dispatch Instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following Dispatch Instructions, and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following Dispatch Instructions, including External Resources, in MWhs during the Operating Day; (iii) demand reduction deviations for Pool-Scheduled Demand Response Resources not following Dispatch Instructions; and (iv) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day. The Real-Time deviations calculation is specified in greater detail in Section III.F.3.2.

#### **III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation.**

- (a) If a Generator Asset has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.
- (b) If a Demand Response Resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the resource should not be dispatched in order to avoid a Minimum Generation Emergency, the Market Participant will be responsible for all Real-Time Demand Reduction Obligation Deviation charges, but will not incur related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.
- (c) Any difference between the actual consumption (Real-Time Load Obligation) of a DARD and the DARD's Demand Bids that clear in the Day-Ahead Energy Market that result from operation in



accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation for the purpose of allocating costs for Real-Time Energy Market NCPC Credits.

- (d) In any hour during which a Capacity Scarcity Condition occurs or ISO New England Operating Procedure No. 4 or ISO New England Operating Procedure No. 7 are implemented, any NCPC Charges that would have been allocated pursuant to Section III.F.3.2 to net positive Real-Time Load Obligation Deviations in an affected Load Zone (and related portion of adjacent External Nodes) are instead allocated and charged to Market Participants based on their pro rata share of the sum of their Real-Time Load Obligation (excluding Real-Time Load Obligations associated with a Postured Dispatchable Asset Related Demand Resource) in all the affected Load Zones and (and related portion of adjacent External Nodes) during the affected hour(s). For purposes of this calculation, the ISO shall apportion any Real-Time Load Obligations and Real-Time Load Obligation Deviations at an External Node equally among the Load Zones to which the External Node is interconnected.

#### **III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits.**

Each Market Participant's pro-rata share of the Real-Time deviations for Real-Time Energy Market NCPC Credits is the following:

- (a) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

- (b) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) or

(Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

- (c) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

**plus,**

- (d) for each Pool-Scheduled Generator Asset and Continuous Storage Generator Asset:

- (i) If the Generator Asset is not following Dispatch Instructions, has cleared Day-Ahead, has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – Desired Dispatch Point) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

- (ii) If the Generator Asset is not following Dispatch Instructions, has cleared Day-Ahead, has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – cleared Day-Ahead MWh) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

**plus,**

(e) for each Pool-Scheduled Demand Response Resource:

- (i) If the Demand Response Resource is being dispatched, is not following Dispatch Instructions, has cleared Day-Ahead, and has not been ordered to stop reducing demand for reliability purposes: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction – Desired Dispatch Point) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

- (ii) If the Demand Response Resource is unavailable and has cleared Day-Ahead: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction – cleared Day-Ahead MWh) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

**plus,**

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation,

where

- (i) each Market Participant's Real-Time Load Obligation Deviation for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub), and
- (ii) for purposes of calculating a Participant's Real-Time Load Obligation Deviation under this subsection (e), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and
- (iii) External Transaction sales curtailed by the ISO are omitted from this calculation.

**plus,**

(g) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation,

where

- (i) each Market Participant's Real-Time Generation Obligation Deviation at External Nodes for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes, and
- (ii) for purposes of calculating a Participant's Real-Time Generation Obligation Deviation under this sub-section (f), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and
- (iii) External Transaction purchases curtailed by the ISO are omitted from this calculation.

**plus,**

(h) the absolute value of the total over all Locations of the Market Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

### **III.F.3.3 Local Second Contingency Protection Resource NCPC Charges.**

Each Market Participant's pro-rata share of the cost for Day-Ahead Energy Market NCPC Credits and Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection is based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region, excluding Real-Time Load Obligations associated with Storage DARDs subject to the following conditions:

- (a) The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating a Market Participant's pro-rata

share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

- (b) For hours in which there is an NCPC cost for a resource providing Local Second Contingency Protection and ISO is selling Emergency Energy to an adjacent Control Area, the scheduled amount of Emergency Energy at the applicable External Node will be included in the calculation of a Market Participant’s pro rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection as if the Emergency Energy sale were a Real-Time Load Obligation within each affected Reliability Region. The pro rata share calculated for the Emergency Energy transaction shall be included in the charges under an agreement for purchase and sale of Emergency Energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency Energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

<b>External Node Common Name</b>	<b>Associated Transmission Facilities</b>	<b>Reliability Region(s)</b>	<b>Allocator</b>
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390/3016) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-7 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line)	Vermont, Vermont Vermont West Central Massachusetts	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described

<b>External Node Common Name</b>	<b>Associated Transmission Facilities</b>	<b>Reliability Region(s)</b>	<b>Allocator</b>
	Alps – Berkshire Line (393Line)  Pleasant Valley – Long Mountain Line (398 Line)	West Central Massachusetts  Connecticut	in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
NY NNC External Node	Northport-Norwalk Harbor (601,602 and 603 Lines)	Connecticut	100% to Connecticut
NY CSC External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(c) For each month, the ISO performs an evaluation of total Local Second Contingency Protection Resource NCP Charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph c, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency Energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Storage DARD.

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge  $_{(Reliability\ Region, month)}$  > .06 X Load Weighted Real-Time LMP  $_{(Reliability\ Region, month)}$

Condition 2 – is the Local Second Contingency Protection Resource Charge %  $_{(Reliability\ Region, month)}$  > 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge %  $_{(Reliability\ Region)}$

Where:

Real-Time Load Obligation  $(\text{Reliability Region, month})$  equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge  $(\text{Reliability Region, month})$  equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation  $(\text{Reliability Region, month})$ .

Load Weighted Real-Time LMP  $(\text{Reliability Region, month})$  equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation  $(\text{Reliability Region, month})$ .

Local Second Contingency Protection Resource Charge %  $(\text{Reliability Region, month})$  equals the Local Second Contingency Protection Resource Charge  $(\text{Reliability Region, month})$  divided by the Load Weighted Real-Time LMP  $(\text{Reliability Region, month})$ .

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge %  $(\text{Reliability Region})$  equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge %  $(\text{Reliability Region, month})$  divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge %  $(\text{Reliability Region})$ , a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge %  $(\text{Reliability Region})$  value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge  $(\text{Reliability Region, month})$  is triggered.

- (ii) Determination of the portion of Local Second Contingency Protection Resource Charge  $(\text{Reliability Region, month})$  to be reallocated –

Local Second Contingency Protection Resource Charge  $(\text{Reliability Region, month})$  to be reallocated =  
Real-Time Load Obligation  $(\text{Reliability Region, month})$  X Min (Condition 1 Rate  $(\text{Reliability Region, month})$ ,  
Condition 2 Rate  $(\text{Reliability Region, month})$ )

Where:

Condition 1 Rate  $(\text{Reliability Region, month})$  equals the Local Second Contingency Protection Resource Charge  $(\text{Reliability Region, month})$  minus .06 times the Load Weighted Real-Time LMP  $(\text{Reliability Region, month})$ .

Condition 2 Rate  $(\text{Reliability Region, month})$  equals the Local Second Contingency Protection Resource Charge  $(\text{Reliability Region, month})$  minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge  $\% (\text{Reliability Region})$  times the Load Weighted Real-Time LMP  $(\text{Reliability Region, month})$ .

(iii) Determination of Local Second Contingency Protection Resource Charge  $(\text{Reliability Region, month})$  reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

$(\text{Real-Time Load Obligation } (\text{Participant, Reliability Region, month}) / \text{Real-Time Load Obligation } (\text{Reliability Region, month})) * \text{Local Second Contingency Protection Resource Charges } (\text{Reliability Region, month})$  to be reallocated

Where:

Real-Time Load Obligation  $(\text{Participant, Reliability Region, month})$  equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

$(\text{Regional Network Load } (\text{Transmission Customer, Reliability Region, month}) / \text{Regional Network Load } (\text{Reliability Region, month})) * \text{Local Second Contingency Protection Resource Charges } (\text{Reliability Region, month})$  to be reallocated

Where:

Regional Network Load  $(\text{Reliability Region, month})$  equals:



The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load (Customer, Reliability Region, month) equals:

The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

#### **III.F.4. NCPD Reporting**

**III.F.4.1. Zonal NCPD Report.** Beginning January 2019, for each month, no later than 20 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating the aggregate dollar amount of NCPD Credits by category paid to the resources located in each Load Zone for each day during that month.

**III.F.4.2. Resource-Specific NCPD Report.** Beginning January 2019, for each month, no later than 90 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating the name of each resource that received NCPD Credits for that month and the total dollar amount of NCPD Credits that each of those resources received for that month.

**III.F.4.3. Operator-Initiated Commitment Report.** Beginning January 2019, for each month, no later than 30 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating each resource commitment made during that month after the Day-Ahead Energy Market for a reason other than minimizing the total production costs of serving load. For each such commitment, the report shall include the start time, the Economic Maximum Limit or Maximum Reduction of the committed resource, the Load Zone in which the committed resource is located, and the reason for the commitment.

## **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:

**Active Demand 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.

**Actual Capacity Provided** is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

**AGC** is automatic generation control.

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

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

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

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

**Alternative Technology Regulation Resource (ATTR)** is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

**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.

**Annual Reconfiguration Transaction** is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

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

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

**Asset** is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

**Asset Registration Process** is the ISO business process for registering an Asset.

**Asset Related Demand** is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration

Process, and is made up of either: (1) 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; (2) a Storage DARD with a consumption capability of at least 0.1 MW; or (3) one or more storage facilities that are not Electric Storage Facilities with an aggregate consumption capability of at least 1 MW.

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

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

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

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

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

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

**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 Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

**Available Energy** is a value that reflects the MWhs of energy available from an Electric Storage Facility for economic dispatch.

**Available Storage** is a value that reflects the MWhs of unused storage available from an Electric Storage Facility for economic dispatch of consumption.

**Average Hourly Load Reduction** is either: (i) the sum of the On-Peak 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; or (ii) the sum of the Seasonal Peak 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. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the 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 On-Peak 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; or (ii) the sum of the Seasonal Peak 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. Electrical energy output and Average Hourly Output shall be determined consistent with the 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.13.7.1.2.2 of Market Rule 1.

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

**Bankruptcy Code** is the United States Bankruptcy Code.

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

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

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

**Binary Storage DARD** is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Binary Storage Facility** is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**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 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 Blackstart O&M calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

**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.

**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 established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

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

**Block** is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

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

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

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

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

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

**Capacity Acquiring Resource** is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

**Capacity Balancing Ratio** is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

**Capacity Base Payment** is the portion of revenue received in the Forward Capacity Market as described in Section III.13.7.1 of Market Rule 1.

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

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

**Capacity 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 as described in Section III.13.7.5.2 of Market Rule 1.

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

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

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

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

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

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

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

**Capacity Performance Bilateral** is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 of Market Rule 1.

**Capacity Performance Payment** is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1.

**Capacity Performance Payment Rate** is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 of Market Rule 1.

**Capacity Performance Score** is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 of Market Rule 1.

**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 Scarcity Condition** is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 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 Transfer Rights (CTRs)** are calculated in accordance with Section III.13.7.5.4.

**Capacity Transferring Resource** is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

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

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

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

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

**Category B Designated Blackstart Resource** has the same meaning as 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 or the demand reduction capability of a Demand Response Resource.

**Cluster Enabling Transmission Upgrade (CETU)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Entry Deadline** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Interconnection System Impact Study (CSIS)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

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

**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 Capacity Commitment Period, 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. 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** is capacity that has achieved FCM Commercial Operation.

**Commission** is the Federal Energy Regulatory Commission.

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

**Common Costs** are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

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

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

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

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

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

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

**Congestion** is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different

from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

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

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

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

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

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

**Continuous Storage ATRR** is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage DARD** is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.



**Continuous Storage Generator Asset** is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage Facility** is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**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.

**Controllable Behind-the-Meter Generation** means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

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

**Coordinated Transaction Scheduling** means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

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

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

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

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

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

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

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

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

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

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

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

**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) of Market Rule 1.

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

**Day-Ahead Demand Reduction Obligation** is defined in Section III.3.2.1(a) of Market Rule 1.

**Day-Ahead Energy Market** means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, 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.

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

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

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

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

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

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

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

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

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

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

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

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

**DDP Dispatchable Resource** is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

**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 Bid Cap** is \$2,000/MWh.

**Demand Capacity Resource** means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

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

**Demand Reduction Offer** is an offer by a Market Participant with a Demand Response Resource to reduce demand.

**Demand Reduction Offer Block-Hours** are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction 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 Demand Reduction 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 Demand Reduction Offer Block-Hours.

**Demand Reduction Threshold Price** is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

**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 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 Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

**Demand Response Asset** is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with Section III.8.1.1.

**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 as determined pursuant to Section III.8.2.

**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 DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

**Demand Response Resource Notification Time** is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts 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 period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

**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, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

**Designated Entity** is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset 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)** means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

**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 Response Resources, change External Transactions, or change the status or consumption of a



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

**Dispatch Zone** means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

**Dispatchable Asset Related Demand (DARD)** is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, 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 Operating Procedures and Manuals.

**Dispatchable Resource** is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

**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 directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that

the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

**DRR Aggregation Zone** is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

**Do Not Exceed (DNE) Dispatchable Generator** is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

**Do Not Exceed Dispatch Point** is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

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

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

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

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

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

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

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

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

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

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

**Economic Maximum Limit or Economic Max** is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

**Economic Minimum Limit or Economic Min** is (a) for a Generator Asset 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 a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

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

**Effective Offer** is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

**EFT** is electronic funds transfer.

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

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

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

**Electric Storage Facility** is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

**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 output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

**EMS** is energy management system.

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

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

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

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

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

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

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

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

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

**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, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

**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, a Market Participant's share of Zonal Capacity Obligation 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.

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

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

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

**Existing Capacity Resource** is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

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

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

**Existing Demand Capacity Resource** is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

**External Transaction Cap** is \$2,000/MWh for External Transactions other than Coordinated External Transactions and \$1,000/MWh for Coordinated External Transactions.



**External Transaction Floor** is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative \$1,000/MWh for Coordinated External Transactions.

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

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

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

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

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

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

**Fast Start Generator** means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

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

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

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

**FCM Charge Rate** is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

**FCM Commercial Operation** is defined in Section III.13.3.8 of Market Rule 1.

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

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

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

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

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

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

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

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

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

**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.

**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 Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**Forward Reserve Offer Cap** is \$9,000/megawatt-month.

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

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

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

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

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

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

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

**FTR 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 device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset 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 Charges** are defined in Section 1.3 of the ISO New England Billing Policy.

**Hourly PER** is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

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

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

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

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

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

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

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

**Inadvertent Energy Revenue Charges or Credits** is defined in Section III.3.2.1(p) 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 supply at the specified Location in the Day-Ahead Energy Market.

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

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

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

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

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

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

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

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

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

**Interconnection Agreement** is the “Large Generator Interconnection Agreement”, the “Small Generator Interconnection Agreement”, or the “Elective Transmission Upgrade Interconnection Agreement”

pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**ISO** means ISO New England Inc.

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

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

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

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

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

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

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

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

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

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

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

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

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

**ITC Agreement** is defined in Attachment M to the OATT.

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

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

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

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

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

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

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

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

**Limited Energy Resource** means a Generator Asset 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. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

**Load Management** means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage 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, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

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

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

**Local Area Facilities** are defined in the TOA.

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



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

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

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

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

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

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

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

**Local Public Policy Transmission Upgrade** is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System

Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

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

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

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

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

**Local Sourcing Requirement (LSR)** is a value calculated as described in Section III.12.2.1 of Market Rule 1.

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

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

**Location** is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

**Locational Marginal Price (LMP)** is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

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

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

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

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

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

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

**LSE** means load serving entity.

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

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

**Manual Response Rate** is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

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

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

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

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

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

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

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

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

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

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

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

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

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

load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

**Maximum Capacity Limit** is a value calculated as described in Section III.12.2.2 of Market Rule 1.

**Maximum Consumption Limit** is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

**Maximum Daily Energy Limit** is the maximum amount of megawatt-hours that a Limited Energy Resource expects to be able to generate in the next Operating Day.

**Maximum Daily Consumption Limit** is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

**Maximum Facility Load** is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

**Maximum Interruptible Capacity** is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

**Maximum Load** is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

**Maximum Number of Daily Starts** is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

**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 an On-Peak Demand Resource or Seasonal Peak 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 On-Peak Demand Resources or Seasonal Peak 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 capability of the 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 capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the 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 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include 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 an On-Peak Demand Resource or Seasonal Peak Demand Resource 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 On-Peak Demand Resources or Seasonal Peak Demand Resources 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 capability of the On-Peak Demand Resource or Seasonal Peak 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 an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak 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.

**Metered Quantity For Settlement** is defined in Section III.3.2.1.1 of Market Rule 1.

**Minimum Consumption Limit** is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

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

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

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

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

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

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

**Minimum Time Between Reductions** is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

**Minimum Total Reserve Requirement**, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

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

**Monthly Capacity Payment** is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

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

**Monthly PER** is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

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

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

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

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

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

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

**MUI** is the market user interface.

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

**MW** is megawatt.

**MWh** is megawatt-hour.

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

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

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

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

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

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

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

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

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

**NEPOOL Agreement** is the agreement among the participants in NEPOOL.

**NEPOOL GIS** is the generation information system.

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

**NEPOOL GIS API Fees** are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

**NEPOOL Participant** is a party to the NEPOOL Agreement.

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

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

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

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

**Net Regional Clearing Price** is described in Section III.13.7.5 of Market Rule 1.

**Net Supply** is energy injected into the transmission or distribution system at a Retail Delivery Point.

**Net Supply Capability** is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

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

**Network Customer** is a Transmission Customer receiving RNS or LNS.

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

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

**Network Resource** is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource

located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

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

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

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

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

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

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

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

**New Demand Capacity Resource** is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

**New Demand Capacity Resource Qualification Package** is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

**New Demand Capacity Resource Show of Interest Form** is described in Section III.13.1.4.1.1.1 of Market Rule 1.

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

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

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

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

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

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

**New Resource Offer Floor Price** is defined in Section III.A.21.2.

**NMPTC** means Non-Market Participant Transmission Customer.

**NMPTC Credit Threshold** is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

**NMPTC Financial Assurance Requirement** is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

**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 Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset 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 Generator Asset 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.13.7.5.1.3.

**Non-Commercial Capacity** is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

**Non-Commercial Capacity Cure Period** is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.



**Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount)** is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

**Non-Designated Blackstart Resource Study Cost Payments** are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

**Non-Dispatchable Resource** is any Resource that does not meet the requirements to be a Dispatchable Resource.

**Non-Hourly Charges** are defined in Section 1.3 of the ISO New England Billing Policy.

**Non-Hourly Requirements** are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

**Non-Incumbent Transmission Developer** is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. “Non-Incumbent Transmission Developer” also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

**Non-Incumbent Transmission Developer Operating Agreement (or NTDOA)** is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

**Non-Market Participant** is any entity that is not a Market Participant.

**Non-Market Participant Transmission Customer** is any entity which is not a Market Participant but is a Transmission Customer.

**Non-Municipal Market Participant** is defined in Section II of the ISO New England Financial Assurance Policy.

**Non-PTF Transmission Facilities (Non-PTF)** are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

**Non-Qualifying** means a Market Participant that is not a Credit Qualifying Market Participant.

**Notice of RBA** is defined in Section 6.3.2 of the ISO New England Billing Policy.

**Notification Time** is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

**Northeastern Planning Protocol** is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: [www.iso-ne.com/static-assets/documents/2015/07/northeastern\\_protocol\\_dmeast.doc](http://www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc).

**NPCC** is the Northeast Power Coordinating Council.

**Obligation Month** means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

**Offer Data** means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of 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 or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

**Offered CLAIM30** is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

**On-Peak Demand Resource** is a type of Demand Capacity 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 Generator Asset or a Load Asset, where such facility 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.

**Passive DR Audit** is the audit performed pursuant to Section III.13.6.1.5.4.

**Passive DR Auditing Period** is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

**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.13.7.1.2 of Market Rule 1.

**PER Proxy Unit** is described in Section III.13.7.1.2.1 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 Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

**Phase I Transfer Credit** is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

**Phase I/II HVDC-TF** is defined in Schedule 20A to Section II of this Tariff.

**Phase I/II HVDC-TF Transfer Capability** is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The “Phase I Transfer Capability” is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

**Phase One Proposal** is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

**Phase II Transfer Credit** is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

**Phase Two Solution** is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

**Planning Advisory Committee** is the committee described in Attachment K of the OATT.

**Planning and Reliability Criteria** is defined in Section 3.3 of Attachment K to the OATT.

**Planning Authority** is an entity defined as such by the North American Electric Reliability Corporation.

**Point(s) of Delivery (POD)** is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

**Point of Interconnection** shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of 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.

**Posting Entity** is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

**Posture** means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

**Posturing Credits** are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

**Power Purchaser** is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

**Principal** is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

**Profiled Load Assets** include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

**Project Sponsor** is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

**Proxy De-List Bid** is a type of bid used in the Forward Capacity Market.

**Provisional Member** is defined in Section I.68A of the Restated NEPOOL Agreement.

**PTO Administrative Committee** is the committee referred to in Section 11.04 of the TOA.

**Public Policy Requirement** is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

**Public Policy Transmission Study** is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.



**Public Policy Local Transmission Study** is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

**Public Policy Transmission Upgrade** is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

**Publicly Owned Entity** is defined in Section I of the Restated NEPOOL Agreement.

**Qualification Process Cost Reimbursement Deposit** is described in Section III.13.1.9.3 of Market Rule 1.

**Qualified Capacity** is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

**Qualified Generator Reactive Resource(s)** is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

**Qualified Non-Generator Reactive Resource(s)** is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

**Qualified Reactive Resource(s)** is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

**Qualified Transmission Project Sponsor** is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

**Queue Position** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Rapid Response Pricing Asset** is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

**Rapid Response Pricing Opportunity Cost** is the NCPC Credit described in Section III.F.2.3.10.

**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.

**Rationing Minimum Limit** is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which an offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

**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) of Market Rule 1.

**Real-Time Adjusted Load Obligation Deviation** is defined in Section III.3.2.1(d) of Market Rule 1.

**Real-Time Commitment NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Congestion Revenue** is defined in Section III.3.2.1(i) of Market Rule 1.

**Real-Time Demand Reduction Obligation** is defined in Section III.3.2.1(c) of Market Rule 1.

**Real-Time Demand Reduction Obligation Deviation** is defined in Section III.3.2.1(e) of Market Rule 1.

**Real-Time Dispatch NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Energy Market** means the purchase or sale of energy, purchase of demand reductions, 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(g) of Market Rule 1.

**Real-Time Energy Market Deviation Energy Charge/Credit** is defined in Section III.3.2.1(g) of Market Rule 1.

**Real-Time Energy Market Deviation Loss Charge/Credit** is defined in Section III.3.2.1(g) of Market Rule 1.

**Real-Time Energy Market NCPC Credits** are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

**Real-Time External Transaction NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Generation Obligation** is defined in Section III.3.2.1(b) of Market Rule 1.

**Real-Time Generation Obligation Deviation** is defined in Section III.3.2.1(d) of Market Rule 1.

**Real-Time High Operating Limit** is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

**Real-Time Load Obligation** is defined in Section III.3.2.1(b) of Market Rule 1.

**Real-Time Load Obligation Deviation** is defined in Section III.3.2.1(d) of Market Rule 1.

**Real-Time Locational Adjusted Net Interchange** is defined in Section III.3.2.1(b) of Market Rule 1.

**Real-Time Locational Adjusted Net Interchange Deviation** is defined in Section III.3.2.1(d) of Market Rule 1.

**Real-Time Loss Revenue** is defined in Section III.3.2.1(l) 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 Offer Change** is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

**Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Prices** means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

**Real-Time Reserve Charge** is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

**Real-Time Reserve Clearing Price** is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

**Real-Time Reserve Credit** is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement 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 described in Section III.1.7.19 of Market Rule 1.

**Real-Time Reserve Opportunity Cost** is defined in Section III.2.7A(b) of Market Rule 1.

**Real-Time Synchronous Condensing NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time System Adjusted Net Interchange** means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

**Receiving Party** is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

**Reference Level** is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

**Regional Benefit Upgrade(s) (RBU)** means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

**Regional Network Load** is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

**Regional Network Service (RNS)** is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

**Regional Planning Dispute Resolution Process** is described in Section 12 of Attachment K to the OATT.

**Regional System Plan (RSP)** is the plan developed under the process specified in Attachment K of the OATT.

**Regional Transmission Service (RTS)** is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

**Regulation** is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

**Regulation and Frequency Response Service** is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

**Regulation Capacity** is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

**Regulation Capacity Requirement** is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

**Regulation Capacity Offer** is an offer by a Market Participant to provide Regulation Capacity.

**Regulation High Limit** is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

**Regulation Low Limit** is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

**Regulation Market** is the market described in Section III.14 of Market Rule 1.

**Regulation Resources** are those Alternative Technology Regulation Resources and Generator Assets that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

**Regulation Service** is the change in output or consumption made in response to changing AGC SetPoints.

**Regulation Service Requirement** is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

**Regulation Service Offer** is an offer by a Market Participant to provide Regulation Service.

**Related Person** is defined pursuant to Section 1.1 of the Participants Agreement.

**Related Transaction** is defined in Section III.1.4.3 of Market Rule 1.

**Reliability Administration Service (RAS)** is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

**Reliability Committee** is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

**Reliability Markets** are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

**Reliability Region** means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

**Reliability Transmission Upgrade** means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability



criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

**Remittance Advice** is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

**Remittance Advice Date** is the day on which the ISO issues a Remittance Advice.

**Renewable Technology Resource** is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

**Re-Offer Period** is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, 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 Quantity For Settlement** is defined in Section III.10.1 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 Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or 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.

**Retirement De-List Bid** is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

**Returning Market Participant** is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

**Revenue Requirement** is defined in Section IV.A.2.1 of the Tariff.

**Reviewable Action** is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

**Reviewable Determination** is defined in Section 12.4(a) of Attachment K to the OATT.

**RSP Project List** is defined in Section 1 of Attachment K to the OATT.

**RTEP02 Upgrade(s)** means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

**RTO** is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission’s corresponding regulation.

**Same Reserve Zone Export Transaction** is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

**Sanctionable Behavior** is defined in Section III.B.3 of Appendix B of Market Rule 1.

**Schedule, Schedules, Schedule 1, 2, 3, 4 and 5** are references to the individual or collective schedules to Section IV.A. of the Tariff.

**Schedule 20A Service Provider (SSP)** is defined in Schedule 20A to Section II of this Tariff.

**Scheduling Service**, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

**Scheduling, System Control and Dispatch Service**, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

**Seasonal Claimed Capability** is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

**Seasonal Claimed Capability Audit** is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

**Seasonal DR Audit** is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

**Seasonal Peak Demand Resource** is a type of Demand Capacity 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 its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in

the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing 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 committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

**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.C 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.

**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).

**Sponsored Policy Resource** is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.

**Stage One Proposal** is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

**Stage Two Solution** is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

**Standard Blackstart Capital Payment** is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

**Start-of-Round Price** is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

**Start-Up Fee** is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset 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 Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

**Station** is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

**Station Going Forward Common Costs** are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

**Station-level Blackstart O&M Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Station-level Specified-Term Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Station-level Standard Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Storage DARD** is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**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 pursuant to Section III.9. 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.

**Supply Offer** is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource,



timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

**Supply Offer Block-Hours** are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

**Synchronous Condenser** is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

**System Condition** is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

**System Impact Study** is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

**System Operator** shall mean ISO New England Inc. or a successor organization.

**System-Wide Capacity Demand Curve** is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

**TADO** is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market

Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

**Tangible Net Worth** is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock; (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

**Technical Committee** is defined in Section 8.2 of the Participants Agreement.

**Ten-Minute Non-Spinning Reserve (TMNSR)** is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

**Ten-Minute Non-Spinning Reserve Service** is the form of Ancillary Service described in Schedule 6 of the OATT.

**Ten-Minute Reserve Requirement** is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**Ten-Minute Spinning Reserve (TMSR)** is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

**Ten-Minute Spinning Reserve Requirement** is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**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)** is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

**Thirty-Minute Operating Reserve Service** is the form of Ancillary Service described in Schedule 7 of the OATT.

**Through or Out Rate (TOUT Rate)** is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

**Through or Out Service (TOUT Service)** means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

**Tie-Line Asset** is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

**Total Available Amount** is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

**Total Blackstart Capital Payment** is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

**Total Blackstart 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 Reserve Requirement**, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**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 Constraint Penalty Factors** are described in Section III.1.7.5 of Market Rule 1.

**Transmission Credit Limit** is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

**Transmission Credit Test Percentage** is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

**Transmission Customer** is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

**Transmission Default Amount** is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

**Transmission Default Period** is defined in Section 3.4.f of the ISO New England Billing Policy.

**Transmission Late Payment Account** is defined in Section 4.2 of the ISO New England Billing Policy.

**Transmission Late Payment Account Limit** is defined in Section 4.2 of the ISO New England Billing Policy.

**Transmission Late Payment Charge** is defined in Section 4.1 of the ISO New England Billing Policy.

**Transmission, Markets and Services Tariff (Tariff)** is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

**Transmission Obligations** are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

**Transmission Operating Agreement (TOA)** is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

**Transmission Owner** means a PTO, MTO or OTO.

**Transmission Provider** is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

**Transmission Requirements** are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

**Transmission Security Analysis Requirement** shall be determined pursuant to Section III.12.2.1.2.

**Transmission Service Agreement (TSA)** is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

**Transmission Upgrade(s)** means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

**UDS** is unit dispatch system software.

**Unconstrained Export Transaction** is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

**Uncovered Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Uncovered Transmission Default Amounts** are defined in Section 3.4.f of the ISO New England Billing Policy.

**Unrated** means a Market Participant that is not a Rated Market Participant.

**Unsecured Covered Entity** is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

**Unsecured Municipal Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Unsecured Municipal Market Participant** is defined in Section 3.3(h) of the ISO New England Billing Policy.

**Unsecured Municipal Transmission Default Amount** is defined in Section 3.4.f of the ISO New England Billing Policy.

**Unsecured Non-Municipal Covered Entity** is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than \$0 under the ISO New England Financial Assurance Policy.

**Unsecured Non-Municipal Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Unsecured Non-Municipal Transmission Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Unsecured Transmission Default Amounts** are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

**Unsettled FTR Financial Assurance** is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

**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 On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated 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 Cap** is \$2,000/MWh.

**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 pursuant to Section III.9. 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.

**Zonal Capacity Obligation** is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

**Zonal Reserve Requirement** is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

## 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, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance 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, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance 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) The following 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) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.
- (iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR 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) An Establish Claimed Capability Audit may be performed only by a Generator Asset.
- (b) The time and date of an Establish Claimed Capability Audit shall be unannounced.
- (c) For a newly commercial Generator Asset:
  - (i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:
    1. Non-intermittent daily cycle hydro;
    2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
    3. Intermittent Generator Assets
  - (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.
- (d) 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 five 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 one Business Day 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.
- (e) 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.
  - (f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.
  - (g) To conduct an Establish Claimed Capability Audit, the ISO shall:
    - (i) Initiate an Establish 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.
    - (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
    - (iii) 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.
  - (h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

<b>Duration Required for an Establish Claimed Capability Audit</b>	
<b>Type</b>	<b>Claimed Capability Audit Duration (Hrs)</b>
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4

Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

- (i) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.2(h).

**III.1.5.1.3. Seasonal Claimed Capability Audits.**

- (a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.
- (b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:
- (i) Non-intermittent daily hydro; and
  - (ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).
- (c) 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.
- (d) Except as provided in Section III.1.5.1.3(n) 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.
- (e) 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.
- (f) 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 fifth 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.
- (g) 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.
- (h) 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(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.
- (i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

<b>Duration Required for a Seasonal Claimed Capability Audit</b>	
<b>Type</b>	<b>Claimed Capability Audit Duration (Hrs)</b>
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2



Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible (Electric Storage)	2
Hydraulic Turbine-Other	
Hydro-Conventional Weekly	2
Fuel Cell	1
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

- (k) 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.
- (l) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, 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.
- (m) 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.

- (n) 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(f).
  - (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(d)(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(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.
- (o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.3(j).

#### **III.1.5.1.3.1 Seasonal DR Audits.**

- (a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

- (b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.
- (c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:
  - (i) At least once every Capability Demonstration Year;
  - (ii) During the months of April through November;
- (d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:
  - (i) At least once every Capability Demonstration Year;
  - (ii) During the months of December through March.
- (e) A Seasonal DR Audit may be performed either:
  - (i) At the request of a Market Participant as described in subsection (f) below; or
  - (ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.
- (f) If a Market Participant requests a Seasonal DR Audit:
  - (i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.
  - (ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.
  - (iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.
  - (iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
  - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:
  - (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth 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 DR Audit.
  - (iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.
  - (iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

- (h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.
- (i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.
- (j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.
- (k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.
- (l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.
- (m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.
- (n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.
- (o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

**III.1.5.1.4. ISO-Initiated Claimed Capability 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 either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both 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 for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.
- (ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset 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 for a Generator Asset 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) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day 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) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.
  - (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
  - (iii) For Generator Assets, 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.
  - (iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
- (f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

<b>Duration Required for an ISO-Initiated Claimed Capability Audit</b>	
<b>Type</b>	<b>Claimed Capability Audit Duration (Hrs)</b>
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4

Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage)	2
Hydraulic Turbine – Other	
Hydro-Conventional Daily Pondage	2
Hydro-Conventional Run of River	
Hydro-Conventional Weekly	
Wind	2
Photovoltaic	
Fuel Cell	
Other Electric Storage (Excludes Hydraulic Turbine – Reversible)	2
Demand Response Resource	1

- (g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource type not listed in Section III.1.5.1.4(f).

### III.1.5.2 ISO-Initiated Parameter Auditing.

- (a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide real-time energy or reserves.
- (b) Generator audits shall be performed using the following methods for the relevant parameter:
- (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 in accordance with Section III.9.5.
  - (vi) **CLAIM30.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
  - (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 electronic Dispatch Instructions.
  - (viii) **Dual Fuel Capability.** A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).
- (c) Demand Response Resource audits shall be performed using the following methods:
- (i) **Maximum Reduction.** The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.
  - (ii) **Demand Response Resource Ramp Rate.** The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.
  - (iii) **Demand Response Resource Start-Up Time.** The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.
  - (iv) **Demand Response Resource Notification Time.** The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.
  - (v) **CLAIM10.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.
  - (vi) **CLAIM30.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
- (d) To conduct an audit based upon historical data, the ISO shall:
- (i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or
  - (ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.

- (e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.
- (f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:
  - (i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.
  - (ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.
- (g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.
- (h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:
  - (i) The 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 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 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 parameter value restriction;
    2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
    3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.



### **III.1.5.3 Reactive Capability Audits.**

- (a) Two types of Reactive Capability Audits may be performed:
  - (i) A Lagging Reactive Capability Audit measures the Generator Asset's ability to provide reactive power to the transmission system at a specified real power output.
  - (ii) A Leading Reactive Capability Audit measures the Generator Asset's ability to absorb reactive power from the transmission system at a specified real power output.
- (b) The ISO shall develop a list of Generator Assets that must conduct Reactive Capability Audits.
- (c) Unless otherwise directed by the ISO, Generator Assets that are required to perform Reactive Capability Audits must perform both a Lagging Reactive Capability Audit and a Leading Reactive Capability Audit.
- (d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.
- (e) The Reactive 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.
- (f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.
- (g) Reactive Capability Audits must be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Generator Asset to conduct Reactive Capability Audits more often than every five years if:
  - (i) there is a change in the Generator Asset that may affect the reactive power capability of the Generator Asset;
  - (ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Generator Asset; or
  - (iii) historical data shows that the amount of reactive power that the Generator Asset can provide to or absorb from the transmission system is higher or lower than the latest audit data.
- (h) The Lead Market Participant may request a waiver of the requirement to conduct a Reactive Capability Audit. The ISO, at its sole discretion, will determine whether and for how long a waiver can be granted.

**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**                    **Transmission Constraint Penalty Factors.**

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is \$10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is \$30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any

transmission constraint is \$30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

### **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, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the 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 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 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 limitations and 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 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.**

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.

### **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 review of historical data for non-intermittent daily cycle hydro.
  - (ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.
  - (iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:
    - a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.
    - b. For a Generator Asset that is off-line and not available for commitment shall be zero.
    - c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.
  - (iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

### **III.1.7.12 Seasonal DR Audit Value of an Active Demand Capacity Resource.**

- (a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through

November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.

- (b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

**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 endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. 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 Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

**III.1.7.18**                    **Ramping.**

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to sanctions for failure to comply as described in **Appendix B**.

**III.1.7.19**                    **Real-Time Reserve Designation.**

The ISO shall determine the Real-Time Reserve Designation for each eligible Resource in accordance with this Section III.1.7.19. The Real-Time Reserve Designation shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve.

**III.1.7.19.1**                **Eligibility.**

To be eligible to receive a Real-Time Reserve Designation, a Resource must meet all of the criteria enumerated in this Section III.1.7.19.1. A Resource that does not meet all of these criteria is not eligible to provide Operating Reserve and will not receive a Real-Time Reserve Designation.

- (1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.
- (2) The Resource must not be part of the first contingency supply loss.
- (3) The Resource must not be designated as constrained by transmission limitations.
- (4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)
- (5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

### **III.1.7.19.2 Calculation of Real-Time Reserve Designation.**

#### **III.1.7.19.2.1 Generator Assets.**

##### **III.1.7.19.2.1.1 On-line Generator Assets.**

The Manual Response Rate used in calculations in this section shall be the lesser of the Generator Asset's offered Manual Response Rate and its audited Manual Response Rate as described in Section III.1.5.2.

- (a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.

- (b) **Ten-Minute Non-Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Non-Spinning Reserve shall be zero. For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit).
  
- (c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

#### **III.1.7.19.2.1.2 Off-line Generator Assets.**

For an off-line Generator Asset that is not a Fast Start Generator, all components of the Real-Time Reserve Designation shall be zero.

- (a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.
  
- (b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).



- (c) **Thirty-Minute Operating Reserve.** For an off-line Fast Start Generator, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Fast Start Generator's Offered CLAIM30, its CLAIM30, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Thirty-Minute Operating Reserve shall be zero, except during the last thirty minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Thirty-Minute Operating Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires), minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Fast Start Generator pursuant to subsection (b) above.

### **III.1.7.19.2.2 Dispatchable Asset Related Demand.**

#### **III.1.7.19.2.2.1 Storage DARDs.**

- (a) **Ten-Minute Spinning Reserve.** For a Storage DARD, Ten-Minute Spinning Reserve shall be calculated as the absolute value of the amount of current telemetered consumption.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.
- (c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

#### **III.1.7.19.2.2.2 Dispatchable Asset Related Demand Other Than Storage DARDs.**

- (a) **Ten-Minute Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit). For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

- (b) **Ten-Minute Non-Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit).
- (c) **Thirty-Minute Operating Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (a) above. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Non-Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (b) above.

### **III.1.7.19.2.3 Demand Response Resources.**

For a Demand Response Resource that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2.

#### **III.1.7.19.2.3.1 Dispatched.**

- (a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be

calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction). For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

- (b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction).
- (c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within thirty minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction) minus the Ten-Minute Spinning Reserve quantity calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

#### **III.1.7.19.2.3.2 Non-Dispatched.**

For a Demand Response Resource that is not being dispatched that is not a Fast Start Demand Response Resource, all components of the Real-Time Reserve Designation shall be zero.

- (a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Demand Response Resource's Offered CLAIM10, its CLAIM10, and its Maximum Reduction.

- (c) **Thirty-Minute Operating Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Demand Response Resource's Offered CLAIM30, its CLAIM30, and its Maximum Reduction, minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Demand Response Resource pursuant to subsection (b) above.

### **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 Resources 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, consumption, or demand reduction levels of Generator Assets, DARDs, or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and 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.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands 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 or demand reduction capability for the pertinent Operating Day.

**III.1.8** [Reserved.]

**III.1.9** Pre-scheduling.

**III.1.9.1** Offer and Bid Caps and Cost Verification for Offers and Bids.

**III.1.9.1.1** Cost Verification of Resource Offers.

The incremental energy values of Supply Offers and Demand Response Resources above \$1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or \$1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than \$1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to \$1,000/MWh, then the adjusted offer for the Resource is set at \$1,000/MWh;

(ii) If the Reference Level value is greater than \$1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

**III.1.9.1.2** Offer and Bid Caps.

- (a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at \$2,000/MWh.
- (b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.
- (c) Supply Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.
- (d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.
- (e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

**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 Generator Asset 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 Generator Assets or Demand Response 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 or Demand Reduction Offers.

#### **III.1.10.1A Energy Market Scheduling.**

The submission of Day-Ahead offers and bids 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) **Locational Demand Bids** – 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 Resources 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 Demand Bid Cap and Virtual Cap.

(b) **External Transactions** – All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets 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 submitted under Section III.1.10.7 and 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 External Transaction 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.
- (c) **Generator Asset Supply Offers** – Market Participants selling into the New England Markets from Generator Assets or External Resources may submit Supply Offers or External Transactions for the supply of energy for the following Operating Day. (Coordinated External Transactions shall be submitted to the ISO in accordance with Section III.1.10.7.A of this Market Rule 1.)

Such Supply Offers:

- (i) Shall specify the Resource and 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 prices and quantities in a Block may each vary on an hourly basis;
  - (ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;
  - (iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type 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 Generator Assets in Section III.A.3 of Appendix A;
  - (iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;
  - (v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including 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 an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and
  - (vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.
- (d) **DARD Demand Bids** – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including 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;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

(iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers** – Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is above the Energy Offer Cap, below the Energy Offer Floor, or below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

- (iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.
  - (iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.
  - (v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.
  - (vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.
  - (vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.
- (f) **Demand Reduction Threshold Price** – The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:
- (a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.
  - (b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.
  - (c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

- (d) A historic threshold price  $P_{th}$  shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.
- (e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} \times \frac{FPI_c}{FPI_h}$$

where  $FPI_h$  is the historic fuel price index for the same month of the previous year, and  $FPI_c$  is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15<sup>th</sup> day of the month preceding the Demand Reduction Threshold Price's effective date.

- (g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction 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, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.
- (h) **Load Estimate** – 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) **Prorated Supply** – In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction 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, Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction 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, Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) **Prorated Demand** – 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) **Virtuals** – 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, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources 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 supply or consumption and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(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 and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

(c) Market Participants offering energy from 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) 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.

#### **III.1.10.3 Self-Scheduled Resources.**

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD 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. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource shall not be Self-Scheduled.

#### **III.1.10.4 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 and Section III.1.10.7.A 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.1.10.5 Dispatchable Asset Related Demand.**

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

- (i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;
- (ii) 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;
- (iii) abide by the ISO maintenance coordination procedures; and
- (iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

#### **III.1.10.6 Electric Storage**

that A storage facility is a facility that is capable of receiving electricity from the grid and storing the energy for later injection of electricity back to the grid. A storage facility may participate in the New England Markets as described below.



- (a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:
- (i) comprise one or more storage facilities at the same point of interconnection;
  - (ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;
  - (iii) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;
  - (iv) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;
  - (v) settle its injection of electricity to the grid as a Generator Asset and its receipt of electricity from the grid as a DARD; and
  - (vi) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.
- (b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:
- (i) satisfy the requirements applicable to an Electric Storage Facility; and
  - (ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and
  - (iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.
- (c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:
- (i) satisfy the requirements applicable to an Electric Storage Facility;
  - (ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;
  - (iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;
  - (iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;
  - (v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time,

Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;

- (vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;
  - (vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and
  - (viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).
- (d) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.
- (e) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.
- (f) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)
- (g) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.
- (h) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

### **III.1.10.7 External Transactions.**

The provisions of this Section III.1.10.7 do not apply to Coordinated 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) [Reserved.]

(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) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) 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.1.10.7.A Coordinated External Transactions.**

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated NERC E-Tag at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would



create or worsen an Emergency, unless applicable procedures governing the Emergency permit the transaction to be scheduled.

### **III.1.10.7.B                    Coordinated Transactions Scheduling Threshold Trigger to Tie Optimization**

#### **(a)        Background and Overview**

This Section III.1.10.B describes the process for filing amendments to the Transmission, Markets and Services Tariff under Section 205 of the Federal Power Act in the event that the production cost savings of the ISO's interchange on the New York – New England AC Interface, including the Northport/Norwalk Line, following the implementation of an inter-regional interchange scheduling process known as Coordinated Transaction Scheduling, are not satisfactory. The determination of whether savings are satisfactory will be based on actions, thresholds and triggers described in this Section III.1.10.7.B. If pursuant to the actions, thresholds and triggers described in this Section III.1.10.7.B, the production costs savings of Coordinated Transaction Scheduling are not satisfactory, and a superior alternative has not become known, the ISO will file tariff amendments with the Commission to implement the inter-regional interchange scheduling process described to the ISO stakeholders in 2011 as Tie Optimization.

If, pursuant to the timetables presented, the ISO determines the thresholds described herein have not triggered, the process for filing amendments to the ISO tariff as described herein ceases, the provisions of this Section III.1.10.7.B become null and void and the ISO will continue to implement Coordinated Transaction Scheduling unless and until future Section 205 filings are pursued to amend Coordinated Transaction Scheduling.

#### **(b)        The Two-Year Analysis**

Within 120 days of the close of the first and second years following the date that Coordinated Transaction Scheduling as an interface scheduling tool is activated in the New England and New York wholesale electricity markets, the External Market Monitor will develop, for presentation to and comment by, New England stakeholders, an analysis, of:

(i)        the Tie Optimization interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the ISO and New York Independent System

Operator received an infinite number of zero bids in the Coordinated Transaction Scheduling process, which utilizes the supply curves and forecasted prices for each market; and

(ii) an optimal interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the two ISOs had an infinite number of zero bids in the Coordinated Transaction Scheduling process, but utilizing actual real-time prices from each market rather than the forecasted prices that were used in the Coordinated Transaction Scheduling process.

The bid production cost savings associated with the Tie Optimization interchange as developed in (i) above for the second year following the date that Coordinated Transaction Scheduling is activated in the New England and New York wholesale electricity markets will reveal the “foregone” production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(b)(1) formula as the term “b.” The difference in bid production cost savings between (i) and (ii) above will reveal the “foregone” bid production cost savings of the Tie Optimization interchange as developed in (i) above rather than an optimal interchange as developed in (ii) above, represented in the Section III.1.10.7.B(b)(1) formula as the term “a.”

This analysis will be consistent with presentations made by the External Market Monitor to the New England stakeholders during 2011 on the issue of the benefits of Coordinated Transaction Scheduling.

(1) Using the above calculations, the External Market Monitor will compute the following ratio:

$b/a$

If, the ratio  $b/a$  is greater than 60% and  $b$  is greater than \$3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(c) Improving Coordinated Transaction Scheduling

(1) If the ratio, developed pursuant to Section III.1.10.7.B(b)(1), is greater than 60% and  $b$  is greater than \$3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(2) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(3) If the ISO declares that the threshold has triggered, the External Market Monitor will provide recommendations of adjustments to the design or operation of Coordinated Transaction Scheduling to improve the production cost savings available from its implementation.

(4) The ISO, considering the input of the New England stakeholders and the recommendation of the External Market Monitor, will develop and implement adjustments to Coordinated Transaction Scheduling. To the extent tariff revisions are necessary to implement the adjustments to Coordinated Transaction Scheduling, the ISO will file such revisions with the Commission as a compliance filing in the Coordinated Transaction Scheduling docket. If no adjustments to Coordinated Transaction Scheduling have been identified, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing.

(d) The Second Analysis

(1) Within 120 days of the close of the twelve months following the date that the adjustments to Coordinated Transaction Scheduling, developed under Section III.1.10.7.B(c), are activated in the New England and New York wholesale electricity markets, the External Market Monitor will present a second analysis to New England stakeholders. The analysis will be consistent with the analysis described in Section III.1.10.7.B(b) but will develop bid production cost savings for the twelve month period during which the adjustments developed in Section III.1.10.7.B(c) are in place.

(2) The bid production cost savings associated with the Tie Optimization interchange as developed in Section III.1.10.7.B(d)(1) will reveal the “foregone” bid production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(d)(3) formula as the term “b.” The different in bid production cost savings between the Tie Optimization interchange and the optimal interchange, as developed in Section III.1.10.7.B(d)(1), will reveal the “foregone” bid production cost savings of the Tie Optimization interchange rather than the optimal interchange, represented in the Section III.1.10.7.B(d)(3) formula as the term “a.”

(3) Using the above calculations, the External Market Monitor will compute the following ratio:

b/a

If the ratio  $b/a$  is greater than 60% and  $b$  is greater than \$3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(4) If the ratio  $b/a$  is greater than 60% and  $b$  is greater than \$3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(5) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(6) If the ISO declares the threshold has triggered, considering the input of the stakeholders and the recommendation of the External Market Monitor, the ISO will determine whether a superior alternative has been proposed. If the ISO and the New York Independent System Operator both determine a superior alternative has been proposed, the ISO will prepare tariff amendments to be filed with the Commission to implement the superior alternative, and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments and will not pursue the balance of the actions required by this Section III.1.10.7.B.

(7) If the ISO determines a superior alternative has not been proposed, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing. Tie Optimization was described for stakeholders in the *Design Basis Document* for NE/NY Inter-Regional Interchange Scheduling presented at a NEPOOL Participants Committee meeting on June 10, 2011.

(e) The Compliance Filing

The ISO will develop tariff language to implement the inter-regional interchange scheduling practice known as Tie Optimization through a compliance filing with the Commission and will present those

amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments.

#### **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 Resources and to direct that schedules be changed to address an actual or potential 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 Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. 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) 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 ISO New England Manual M-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. The External Transaction re-offer provisions of this Section III.1.10.9(c) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) 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 Generator Assets), and the quantity and price pairs of its Blocks may be modified.
  - (ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.
- (d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.
- (e) 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. A Market Participant may not request to Self-Schedule a Demand Response Resource. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.
- (f) 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(c), 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 at a specified value. 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 at or above the requested amount for the hour in question.

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

(i) 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 or Consumption and Demand Reduction.**

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) 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; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) 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 Dispatchable Resources.**

With the exception of Settlement Only Resources, Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, nuclear-powered Resources and photovoltaic Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

- (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 Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable 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 for a Dispatchable Resource 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.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind and hydro Intermittent Power Resources that are not Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

(i) A wind or hydro Intermittent Power Resource not capable of receiving and responding to electronic Dispatch Instructions will be manually dispatched.

(ii) A Market Participant may elect, but is not required, to have a wind or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.

(iii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.

(f) The ISO may request that dual-fuel Generator Assets 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-fuel Generator Assets 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-fuel Generator Assets 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 Dispatchability Requirements for Intermittent Power Resources.**

- (a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.
- (b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

#### **III.1.11.6 Non-Dispatchable Resources.**

Non-Dispatchable Resources are subject to the following requirements:

(a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource 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.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

### **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, DRR Aggregation 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 electric 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 resources 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 Offer Data, 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. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices shall be determined every five minutes and 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. 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 zonal 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 power flow solution produced by the State Estimator for the pricing interval, 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 Adjustment for Rapid Response Pricing Assets.**

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO, is in a dispatchable mode, and is not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee, No-Load Fee, or Interruption Cost is specified in the submitted Offer Data, a value of zero shall be used; if no Minimum Run Time or Minimum Reduction Time is specified in the submitted Offer Data, or if the submitted Minimum Run Time or Minimum Reduction Time is less than 15 minutes, a duration of 15 minutes shall be used; and the energy offer after adjustment shall not exceed \$2,000/MWh.

- (a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Binary Storage DARD, its Minimum Consumption Limit shall be set to zero; if the Rapid Response Pricing Asset is a Fast Start Demand Response Resource, its Minimum Reduction shall be set to zero.
- (b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.
- (c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.
- (d) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.



(e) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.

### **III.2.5 Calculation of Nodal Real-Time 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 power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), 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 Generator Assets (excluding Settlement Only Resources), Demand Response Resources, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demands with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply or consume 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 output 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.2.7A(c); and (5) the effect on transmission losses caused by the increment of load, generation and demand reduction. 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. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed for every five-minute interval, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the pricing 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.

### **III.2.6 Calculation of Nodal Day-Ahead 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, Demand Reduction 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 an optimization method to minimize energy cost, 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 output 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 supply. 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.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: 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 supply at the Generator Asset's Economic Maximum Limit and demand reduction at the Demand Response Resource's Maximum Reduction, 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 External Transaction 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, Demand Reduction 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 Generator Assets, dispatched Demand Response Resources, 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 Generator Assets (excluding Settlement Only Resources),

dispatched Demand Response Resources, 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 supply (including fixed External Transaction purchases) with all possible Generator Assets off line and with all remaining Generator Assets at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess 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 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 Generator Assets 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 Generator Assets (excluding Settlement Only Resources); and

(iii) If power balance not achieved in step (ii), set LMP values to Energy Offer Floor and reduce all Generator Assets 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 and DRR Aggregation Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone or DRR Aggregation Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and DRR Aggregation 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, Dispatch Zones, and Reserve Zones and add or subtract Reliability Regions, Load Zones, Dispatch 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 is greater than 75 percent of the total 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 obtain Operating Reserve in Real-Time to serve Operating Reserve requirements for the system and each Reserve Zone on a jointly optimized basis with the calculation of nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to maximize social surplus, 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 Generator Assets (excluding Settlement Only Resources), Demand Response Resources and Dispatchable Asset Related Demands 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 meet the system and zonal Operating Reserve requirements or there is a deficiency in available Operating Reserve, in which case Real-Time Reserve Clearing Prices shall be set as described in Section III.2.7A(b) and Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands that were re-dispatched to meet the applicable Operating Reserve requirement. The Real-Time Reserve Opportunity Cost of a Resource shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve.

(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 the following Reserve Constraint Penalty Factors:

<b>Real-Time Requirement</b>	<b>Reserve Constraint Penalty Factor</b>
Zonal Reserve Requirement (combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone)	\$250/MWh
Minimum Total Reserve Requirement (does not include Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	\$1000/MWh
Total Reserve Requirement (includes Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	\$250/MWh
Ten-Minute Reserve Requirement (combined amount of TMSR and TMNSR required system-wide)	\$1500/MWh

Ten-Minute Spinning Reserve Requirement (amount of TMSR required system-wide)	\$50/MWh
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The Reserve Constraint Penalty Factors 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 for every five-minute interval, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of zonal Real-Time Reserve Clearing Prices based on system conditions for the pricing 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.

### **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 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**

**Table of Contents**

- III.A.1. Introduction and Purpose: Structure and Oversight: Independence
  - III.A.1.1. Mission Statement
  - III.A.1.2. Structure and Oversight
  - III.A.1.3. Data Access and Information Sharing
  - III.A.1.4. Interpretation
  - III.A.1.5. Definitions
  
- III.A.2. Functions of the Market Monitor
  - III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor
  - III.A.2.2. Functions of the External Market Monitor
  - III.A.2.3. Functions of the Internal Market Monitor
  - III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions
    - III.A.2.4.1. Purpose
    - III.A.2.4.2. Conditions for the Imposition of Mitigation Measures
    - III.A.2.4.3. Applicability
    - III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*
    - III.A.2.4.5. Duration of Mitigation
  
- III.A.3. Consultation Prior to Determination of Reference Levels for Physical Parameters and Financial Parameters of Resources; Fuel Price Adjustments
  - III.A.3.1. Consultation Prior to Offer
  - III.A.3.2. Dual Fuel Resources
  - III.A.3.3. Market Participant Access to its Reference Levels
  - III.A.3.4. Fuel Price Adjustments
  
- III.A.4. Physical Withholding
  - III.A.4.1. Identification of Conduct Inconsistent with Competition

III.A.4.2. Thresholds for Identifying Physical Withholding

III.A.4.2.1. Initial Thresholds

III.A.4.2.2. Adjustment to Generating Capacity

III.A.4.2.3. Withholding of Transmission

III.A.4.2.4. Resources in Congestion Areas

III.A.4.3. Hourly Market Impacts

III.A.5. Mitigation

III.A.5.1. Resources with Capacity Supply Obligations

III.A.5.1.1. Resources with Partial Capacity Supply Obligations

III.A.5.2. Structural Tests

III.A.5.2.1. Pivotal Supplier Test

III.A.5.2.2. Constrained Area Test

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market

III.A.5.5. Mitigation by Type

III.A.5.5.1. General Threshold Energy Mitigation

III.A.5.5.1.1. Applicability

III.A.5.5.1.2. Conduct Test

III.A.5.5.1.3. Impact Test

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test

III.A.5.5.2. Constrained Area Energy Mitigation

III.A.5.5.2.1. Applicability

III.A.5.5.2.2. Conduct Test

III.A.5.5.2.3. Impact Test

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test

III.A.5.5.3. Manual Dispatch Energy Mitigation

III.A.5.5.3.1. Applicability

III.A.5.5.3.2. Conduct Test

III.A.5.5.3.3. Consequence of Failing the Conduct Test

III.A.5.5.4. General Threshold Commitment Mitigation

III.A.5.5.4.1. Applicability

III.A.5.5.4.2. Conduct Test

III.A.5.5.4.3. Consequence of Failing Conduct Test

- III.A.5.5.5. Constrained Area Commitment Mitigation
      - III.A.5.5.5.1. Applicability
      - III.A.5.5.5.2. Conduct Test
      - III.A.5.5.5.3. Consequence of Failing Test
    - III.A.5.5.6. Reliability Commitment Mitigation
      - III.A.5.5.6.1. Applicability
      - III.A.5.5.6.2. Conduct Test
      - III.A.5.5.6.3. Consequence of Failing Test
    - III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation
      - III.A.5.5.7.1. Applicability
      - III.A.5.5.7.2. Conduct Test
      - III.A.5.5.7.3. Consequence of Failing Conduct Test
    - III.A.5.5.8. Low Load Cost
  - III.A.5.6. Duration of Energy Threshold Mitigation
  - III.A.5.7. Duration of Commitment Mitigation
  - III.A.5.8. Duration of Start-Up Fee and No-Load Mitigation
  - III.A.5.9. Correction of Mitigation
  - III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process
- III.A.6. Physical and Financial Parameter Offer Thresholds
  - III.A.6.1. Time-Based Offer Parameters
  - III.A.6.2. Financial Offer Parameters
  - III.A.6.3. Other Offer Parameters
- 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 Parameter
  - III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Supply Offers
    - III.A.7.2.1. Order of Reference Level Calculation
    - III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation
  - III.A.7.3. Accepted Offer-Based Reference Level
  - III.A.7.4. LMP-Based Reference Level

- III.A.7.5. Cost-based Reference Level
  - III.A.7.5.1. Estimation of Incremental Operating Cost
- III.A.8. [Reserved.]
- III.A.9. Regulation
- III.A.10. Demand Bids
- III.A.11. Mitigation of Increment Offers and Decrement Bids
  - III.A.11.1. Purpose
  - III.A.11.2. Implementation
    - III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids
  - III.A.11.3. Mitigation Measures
  - III.A.11.4. Monitoring and Analysis of Market Design and Rules
- III.A.12. Cap on FTR Revenues
- 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
  - III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market
  - III.A.13.3. Monitoring of Transmission Facility Outage Scheduling
  - III.A.13.4. Monitoring of Forward Reserve Resources
  - III.A.13.5. Imposition of Sanctions
- III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement
- III.A.15. Request for Additional Cost Recovery
  - III.A.15.1. Filing Right
  - III.A.15.2. Contents of Filing
  - III.A.15.3. Review by Internal Market Monitor Prior to Filing
  - III.A.15.4. Cost Allocation



- III.A.16. ADR Review of Internal Market Monitor Mitigation Actions
  - III.A.16.1. Actions Subject to Review
  - III.A.16.2. Standard of Review
  
- III.A.17. Reporting
  - III.A.17.1. Data Collection and Retention
  - III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor
    - III.A.17.2.1. Monthly Report
    - III.A.17.2.2. Quarterly Report
    - III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market
    - III.A.17.2.4. Annual Review and Report by the Internal Market Monitor
  - III.A.17.3. Periodic Reporting by the External Market Monitor
  - III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications with Government Agencies
    - III.A.17.4.1. Routine Communications
    - III.A.17.4.2. Additional Communications
    - III.A.17.4.3. Confidentiality
  - III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators
  
- III.A.18. Ethical Conduct Standards
  - III.A.18.1. Compliance with ISO New England Inc. Code of Conduct
  - III.A.18.2. Additional Ethical Conduct Standards
    - III.A.18.2.1. Prohibition on Employment with a Market Participant
    - III.A.18.2.2. Prohibition on Compensation for Services
    - III.A.18.2.3. Additional Standards Application to External Market Monitor
  
- III.A.19. Protocols on Referrals to the Commission of Suspected Violations
  
- III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes

- III.A.21. Review of Offers From New Resources in the Forward Capacity Market
  - III.A.21.1. Offer Review Trigger Prices
    - III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction
    - III.A.21.1.2. Calculation of Offer Review Trigger Prices
  - III.A.21.2. New Resource Offer Floor Prices and Offer Prices
  - III.A.21.3. Special Treatment of Certain Out-of-Market Capacity Resources in the Eighth Forward Capacity Auction
- III.A.22. [Reserved]
- III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market
  - III.A.23.1. Pivotal Supplier Test
  - III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal
  - III.A.23.3. Pivotal Supplier Test Notification of Results
  - III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test
- III.A.24 Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market
- EXHIBIT 1 [Reserved]
- EXHIBIT 2 [Reserved]
- EXHIBIT 3 [Reserved]
- EXHIBIT 4 [Reserved]
- 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, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this *Appendix A*, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

### **III.A.3.2. Dual Fuel Resources.**

In evaluating bids or offers under this *Appendix A* for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

- (a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.
- (b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

### **III.A.3.3. Market Participant Access to its Reference Levels.**

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

### **III.A.3.4. Fuel Price Adjustments.**

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer

or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus \$2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1 or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2

2 or more	6
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#### **III.A.4. Physical Withholding.**

##### **III.A.4.1. Identification of Conduct Inconsistent with Competition.**

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

- (a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
- (b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,
- (c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
- (d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

##### **III.A.4.2. Thresholds for Identifying Physical Withholding.**

###### **III.A.4.2.1. Initial Thresholds.**

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

- (a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
- (b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

- (c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

#### **III.A.4.2.2. Adjustment to Generating Capacity.**

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

#### **III.A.4.2.3. Withholding of Transmission.**

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

#### **III.A.4.2.4. Resources in Congestion Areas.**

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

#### **III.A.4.3. Hourly Market Impacts.**

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

#### **III.A.5. Mitigation.**

##### **III.A.5.1. Resources with Capacity Supply Obligations.**



Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

#### **III.A.5.1.1. Resources with Partial Capacity Supply Obligations.**

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

- (a) all Supply Offer parameters shall be reviewed for economic withholding;
- (b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;
- (c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

#### **III.A.5.2. Structural Tests.**

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

- (a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;
- (b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

##### **III.A.5.2.1. Pivotal Supplier Test.**

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

#### **III.A.5.2.2. Constrained Area Test.**

A Resource is considered to be within a constrained area if:

- (a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;
- (b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than \$25/MWh.

#### **III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.**

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

#### **III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.**

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

- (a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
- (b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

### **III.A.5.5. Mitigation by Type.**

#### **III.A.5.5.1. General Threshold Energy Mitigation.**

##### **III.A.5.5.1.1. Applicability.**

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

##### **III.A.5.5.1.2. Conduct Test.**

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or \$100/MWh, whichever is lower. Offer block prices below \$25/MWh are not subject to the conduct test.

##### **III.A.5.5.1.3. Impact Test.**

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or \$100/MWh, whichever is lower as determined by the real-time impact test.

##### **III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.**

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

### **III.A.5.5.2. Constrained Area Energy Mitigation.**

#### **III.A.5.5.2.1. Applicability.**

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

#### **III.A.5.5.2.2. Conduct Test.**

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or \$25/MWh, whichever is lower.

#### **III.A.5.5.2.3. Impact Test.**

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or \$25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

#### **III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.**

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

### **III.A.5.5.3. Manual Dispatch Energy Mitigation.**

#### **III.A.5.5.3.1. Applicability.**

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

#### **III.A.5.5.3.2. Conduct Test.**

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

#### **III.A.5.5.3.3. Consequence of Failing the Conduct Test.**

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

#### **III.A.5.5.4. General Threshold Commitment Mitigation.**

##### **III.A.5.5.4.1. Applicability.**

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

##### **III.A.5.5.4.2. Conduct Test.**

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

##### **III.A.5.5.4.3. Consequence of Failing Conduct Test.**

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

#### **III.A.5.5.5. Constrained Area Commitment Mitigation.**

##### **III.A.5.5.5.1. Applicability.**

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

##### **III.A.5.5.5.2. Conduct Test.**

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

#### **III.A.5.5.3. Consequence of Failing Test.**

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

#### **III.A.5.5.6. Reliability Commitment Mitigation.**

##### **III.A.5.5.6.1. Applicability.**

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

- i. local first contingency;
- ii. local second contingency;
- iii. VAR or voltage;
- iv. distribution (Special Constraint Resource Service);
- v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

##### **III.A.5.5.6.2. Conduct Test.**

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

##### **III.A.5.5.6.3. Consequence of Failing Test.**

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

#### **III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.**

##### **III.A.5.5.7.1. Applicability.**

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

**III.A.5.5.7.2. Conduct Test.**

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

**III.A.5.5.7.3. Consequence of Failing Conduct Test.**

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

**III.A.5.5.8. Low Load Cost.**

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

- (a) If the Resource is starting from an offline state, the Start-Up Fee;
- (b) The sum of the No Load Fees for the Commitment Period; and
- (c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

### **III.A.5.6. Duration of Energy Threshold Mitigation.**

Any mitigation imposed pursuant to Sections III.A.5.5.1 “General Threshold Energy Mitigation” or III.A.5.5.2 “Constrained Area Energy Mitigation” is in effect for the following duration:

- (a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:
  - i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,
  - ii. for constrained area energy mitigation, the Resource is not located within a constrained area.
- (b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 “Constrained Area Energy Mitigation”), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 “Manual Dispatch Energy Mitigation” is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource’s Node.

### **III.A.5.7. Duration of Commitment Mitigation.**

Any mitigation imposed pursuant to Sections III.A.5.5.4 “General Threshold Commitment Mitigation”, III.A.5.5.5 “Constrained Area Commitment Mitigation”, or III.A.5.5.6 “Reliability Commitment Mitigation” is in effect for the duration of the Commitment Period.

### **III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.**

Any mitigation imposed pursuant to Sections III.A.5.5.7 “Start-Up Fee and No-Load Fee Mitigation” is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

### **III.A.5.9. Correction of Mitigation.**

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as



part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

#### **III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.**

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

#### **III.A.6. Physical and Financial Parameter Offer Thresholds.**

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

##### **III.A.6.1. Time-Based Offer Parameters.**

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

##### **III.A.6.2. Financial Offer Parameters.**

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

### **III.A.6.3. Other Offer Parameters.**

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

### **III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.**

Market Participants are responsible for providing the Internal Market Monitor with all the information and data necessary for the Internal Market Monitor to calculate up-to-date Reference Levels for each of a Market Participant's 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 Offers.**

The Reference Levels for Start-Up Fees, No-Load Fees, Interruption Costs 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 an offer according to the following hierarchy, under which the first method that can be calculated is used:

- (a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
- (b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
- (c) cost-based Reference Levels pursuant to Section III.A.7.5.

**III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.**

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

- (a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
- (b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
- (c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
- (d) For any Operating Day for which, during the previous 90 days:
  - (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
  - (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
- (e) When in any hour the incremental energy parameter of an offer, including adjusted offers pursuant to Section III.2.4, is greater than \$1,000/MWh.

For the purposes of this subsection:

- i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.
  - ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.
  - iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.
  - iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.
- (e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.
- (f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:
- (i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,
  - (ii) No-Load Fee or its corresponding fuel blends,
  - (iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,
  - (iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and
  - (v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

### **III.A.7.3. Accepted Offer-Based Reference Level.**

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

### **III.A.7.4. LMP-Based Reference Level.**

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

### **III.A.7.5. Cost-Based Reference Level.**

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant 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. All cost estimates, including opportunity cost estimates, must be quantified and analytically supported.
- (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/Reduction:

$(\text{incremental heat rate} * \text{fuel costs}) + (\text{emissions rate} * \text{emissions allowance price}) + \text{variable operating and maintenance costs} + \text{opportunity costs.}$

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

- (a) emissions limits;
- (b) water storage limits;
- (c) other operating permits that limit production of energy; and
- (d) reducing electricity consumption.

No-Load:

$(\text{no-load fuel use} * \text{fuel costs}) + (\text{no-load emissions} * \text{emission allowance price})$   
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up/Interruption:

$(\text{start-up fuel use} * \text{fuel costs}) + (\text{start-up emissions} * \text{emission allowance price}) + \text{start-up variable and maintenance costs} + \text{other start-up costs that are not fuel, emissions or variable and maintenance costs.}$

### **III.A.8. [Reserved.]**

### **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 the Energy Market 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.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.
- (c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.
- (d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.
- (e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.
- (f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

#### **III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.**

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

**III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.**

*Appendix G* of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

**III.A.13.4. Monitoring of Forward Reserve Resources.**

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this *Appendix A*. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

**III.A.13.5. Imposition of Sanctions.**

*Appendix B* of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer *Appendix B* in accordance with the provisions thereof.

**III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.**

Article 5 of the form of Cost-of-Service Agreement in *Appendix I* to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Market 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. Cost Recovery Request Following Capping.**

If as a result of an offer being capped under Section III.1.9, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was capped, the Market Participant may, within 20 days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit an additional cost recovery request to the Internal Market Monitor.

A request under this Section III.A.15 may seek recovery of additional costs incurred for the duration of the period of time for which the Resource was operated at the cap.

#### **III.A.15.1.1. Timing and Contents of Request.**

Within 20 days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant requesting additional cost recovery under this Section III.A.15.1 shall submit to the Internal Market Monitor a request in writing detailing: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data, documentation and calculations for those costs; and (ii) an explanation of why the actual costs of operating the Resource exceeded the capped costs.

#### **III.A.15.1.2. Review by Internal Market Monitor.**

To evaluate a Market Participant's request, the Internal Market Monitor shall use the data, calculations and explanations provided by the Market Participant to verify the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, using the same standards and methodologies the Internal Market Monitor uses to evaluate requests to update Reference Levels under Section III.A.3 of Appendix A. To the extent the Market Participant's request warrants additional cost recovery, the Internal Market Monitor shall reflect that adjustment in the Resource's Reference Levels for the period covered by the request. The ISO shall then re-apply the cost verification and capping formulas in Section III.1.9 using the updated Reference Levels to re-calculate the adjustments to the Market Participant's offers required thereunder, and then shall calculate additional cost recovery using the adjusted offer values.

Within 20 days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the Market Participant's request, detailing (i) the extent to which it agrees with the request with supporting explanation, and (ii) a calculation of the additional cost recovery. Changes to

credits and charges resulting from an additional cost recovery request shall be included in the Data Reconciliation Process.

#### **III.A.15.1.3. Cost Allocation.**

The ISO shall allocate charges to Market Participants for payment of any additional cost recovery granted under this Section III.A.15.1 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.15.2. Section 205 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, as a result of a request under Section III.A.15.1 being denied in whole or in part,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was mitigated or the Section III.A.15.1 request was denied, the Market Participant may submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. For filings to address cost recovery under Section III.A.15.2(a), the filing must be made within sixty days of receipt of the first Invoice issued containing credits or charges for the applicable Operating Day. For filings to address cost recovery under Section III.A.15.2(b), the filing must be made within sixty days of receipt of the first Invoice issued that reflects the denied request for additional cost recovery under Section III.A.15.1.

A request under this Section III.A.15.2 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having a Section III.A.15.1 request denied, costs incurred for the duration of the period of time addressed in the Section III.A.15.1 request.

#### **III.A.15.2.1. Contents of Filing.**

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data

and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource, as reflected in the original offer and to the extent not recovered under Section III.A.15.1, exceeded the costs as reflected in the capped offer; (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.15.2.2. Review by Internal Market Monitor Prior to Filing.**

Within twenty days of the receipt of the applicable Invoice, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15.2 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2.1 (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.15.2 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.15.2.

#### **III.A.15.2.3. 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 metered demand reported to the ISO.

### **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, NCP costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

**III.A.17.3. Periodic Reporting by the External Market Monitor.**

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of *Appendix A*. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

- (i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.
- (ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.
- (iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.
- (iv) Review and assessment of the effectiveness of *Appendix A* and the administration of *Appendix A* by the Internal Market Monitor for consistency and compliance with the terms of *Appendix A*.
- (v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

#### **III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.**

##### **III.A.17.4.1. Routine Communications.**

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

##### **III.A.17.4.2. Additional Communications.**

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

- (a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;
- (b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;
- (c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,
- (d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

#### **III.A.17.4.3. Confidentiality.**

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

#### **III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.**

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets (“authorized government agencies”). With respect to state regulatory bodies and state attorneys general (“authorized state agencies”), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government

agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

### **III.A.18. Ethical Conduct Standards.**

#### **III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.**

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as *Exhibit 5*.

#### **III.A.18.2. Additional Ethical Conduct Standards.**

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

**III.A.18.2.1. Prohibition on Employment with a Market Participant.**

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

**III.A.18.2.2. Prohibition on Compensation for Services.**

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

**III.A.18.2.3. Additional Standards Applicable to External Market Monitor.**

In addition to the standards referenced in the remainder of this Section 18 of *Appendix A*, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

**III.A.19. Protocols on Referral to the Commission of Suspected Violations.**

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the

Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

- (B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information
  - (1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);
  - (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
  - (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
  - (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
  - (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;
  - (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
  - (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

**III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.**

- (A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.
- (B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information.
  - (1) A detailed narrative describing the perceived market design flaw(s);
  - (2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;
  - (3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;
  - (4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

**III.A.21. Review of Offers From New Resources in the Forward Capacity Market.**

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

**III.A.21.1. Offer Review Trigger Prices.**

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8 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 Forward Capacity Auction.**

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the twelfth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2021) shall be as follows:

<b>Generating Capacity Resources</b>	
<b>Technology Type</b>	<b>Offer Review Trigger Price (\$/kW-month)</b>
combustion turbine	\$6.503
combined cycle gas turbine	\$7.856
on-shore wind	\$11.025

<b>Demand Capacity Resources - Commercial and Industrial</b>	
<b>Technology Type</b>	<b>Offer Review Trigger Price (\$/kW-month)</b>
Load Management and/or previously installed Distributed Generation	\$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	\$0.000

<b>Demand Capacity Resources – Residential</b>	
<b>Technology Type</b>	<b>Offer Review Trigger Price (\$/kW-month)</b>
Load Management	\$7.559



previously installed Distributed Generation	\$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	\$0.000

**Other Resources**

All other technology types	Forward Capacity Auction Starting Price
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Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

**III.A.21.1.2. Calculation of Offer Review Trigger Prices.**

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. 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 Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<b>Cost Component</b>	<b>Index</b>
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"
steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay: <ul style="list-style-type: none"> <li>- Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</li> <li>- On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</li> </ul>
other labor	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: <ul style="list-style-type: none"> <li>- Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</li> <li>- On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</li> </ul>
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"
fuel inventories	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<b>Cost Component</b>	<b>Index</b>
labor, administrative and general	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: <ul style="list-style-type: none"> <li>- Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</li> <li>- On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</li> </ul>
materials and contract services	BLS-PPI "Materials and Components for Construction"

site leasing costs	Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”
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(3) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 above will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub On-Peak electricity prices for the months in the Capacity Commitment Period beginning June 1, 2021, as published by ICE.

(5) Renewable energy credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO’s web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

**III.A.21.2. New Resource Offer Floor Prices and Offer Prices.**

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be \$0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the

requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing

market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in

Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

**III.A.22. [Reserved.]**

**III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.**

**III.A.23.1. Pivotal Supplier Test.**

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.



For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

- (a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;
- (b) For each modeled import-constrained Capacity Zone, the greater of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
- (c) For each modeled export-constrained Capacity Zone, the lesser of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone plus, for each external interface connected to the export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Maximum Capacity Limit of the export-constrained Capacity Zone, and;
- (d) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

- (e) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone;  
and

- (f) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

**III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.**

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

- (a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.
- (b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

**III.A.23.3. Pivotal Supplier Test Notification of Results.**

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

**III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.**

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Capacity Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import

Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

#### **III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.**

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

- i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than
- ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then
- iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

- iv. the Lead Market Participant's annual capacity revenue from the Lead Market

Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

- v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.
- vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

**SECTION III**  
**MARKET RULE 1**

**APPENDIX F**  
**NET COMMITMENT PERIOD COMPENSATION ACCOUNTING**

**APPENDIX F**  
**NCPC ACCOUNTING**  
Table of Contents

III.F.1. General

III.F.2. NCPC Credits

- III.F.2.1. Day-Ahead Energy Market NCPC Credits
  - III.F.2.1.1. Eligibility for Credit.
  - III.F.2.1.2. Settlement Period.
  - III.F.2.1.3. Eligible Quantity.
  - III.F.2.1.3.A Hourly Bid
  - III.F.2.1.4. Hourly Cost.
  - III.F.2.1.5. Hourly Revenue.
  - III.F.2.1.6. General Credit Calculation.
  - III.F.2.1.7. Credit Calculation for Fast Start Generators, Flexible DNE Dispatchable Generators, Fast Start Demand Response Resources and Binary Storage DARDs Based on Daily Starts, and for Continuous Storage Generator Assets and Continuous Storage DARDs.
- III.F.2.2. Real-Time Energy Market NCPC Credits
  - III.F.2.2.1. Eligibility for Credit.
  - III.F.2.2.2. Real-Time Commitment NCPC Credits.
    - III.F.2.2.2.1. Settlement Period.
    - III.F.2.2.2.2. Eligible Quantity.
    - III.F.2.2.2.3. Interval Cost.
    - III.F.2.2.2.3.A Interval Bid.
    - III.F.2.2.2.4. Interval Revenue.
    - III.F.2.2.2.5. Credit Calculation for Generator Assets and Demand Response Resources.
    - III.F.2.2.2.6. [Reserved.]
    - III.F.2.2.2.7. Credit Calculation for Binary Storage DARDs.
    - III.F.2.2.2.8. Resources with Commitment in the Day-Ahead Energy Market.

- III.F.2.2.3. Real-Time Dispatch NCPC Credits for Generator Assets and Demand Response Resources.
  - III.F.2.2.3.1. Settlement Period.
  - III.F.2.2.3.2. Eligible Quantity.
  - III.F.2.2.3.3. Interval Cost.
  - III.F.2.2.3.4. Interval Revenue.
  - III.F.2.2.3.5. Credit Calculation.
- III.F.2.2.4. Real-Time Dispatch NCPC Credits for Storage DARDs.
  - III.F.2.2.4.1. Settlement Period.
  - III.F.2.2.4.2. Eligible Quantity.
  - III.F.2.2.4.3. Interval Cost.
  - III.F.2.2.4.4. Interval Bid.
  - III.F.2.2.4.5. Credit Calculation.
- III.F.2.2.5. Real-Time Dispatch Lost Opportunity Cost NCPC Credits.
  - III.F.2.2.5.1. Maximum Net Revenue or Maximum Net Benefit.
  - III.F.2.2.5.2. Actual Net Revenue or Actual Net Benefit.
  - III.F.2.2.5.3. Credit Calculation.
- III.F.2.3. Special Case NCPC Credit Calculations
  - III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits
  - III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits
  - III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)
  - III.F.2.3.4. [Reserved.]
  - III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits
  - III.F.2.3.6. Cancelled Start NCPC Credits
  - III.F.2.3.7. Hourly Shortfall NCPC Credits
  - III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability
  - III.F.2.3.9. Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured for Reliability and Demand Response Resources Postured for Reliability
  - III.F.2.3.10. Rapid Response Pricing Opportunity Cost NCPC Credits Resulting from Commitment of Rapid Response Pricing Assets

- III.F.2.4. Apportionment of NCPC Credits
- III.F.2.5. Credit Designation for Purposes of NCPC Cost Allocation
- III.F.3. Charges for NCPC
  - III.F.3.1 Cost Allocation
    - III.F.3.1.1 Day-Ahead Energy Market NCPC Cost Allocation
    - III.F.3.1.2 Real-Time Energy Market NCPC Cost Allocation
    - III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation
  - III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits
  - III.F.3.3 Local Second Contingency Protection Resource NCPC Charges
- III.F.4. NCPC Reporting



## NCPC ACCOUNTING

### III.F.1. General.

For purposes of NCPC calculations:

- a. Effective Offers.** An Effective Offer for a Resource is (1) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to commit the Resource and (2) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to dispatch the Resource at a Desired Dispatch Point above its Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit, and is subject to the following conditions:
- i. The Effective Offer used in making the decision to commit the Resource establishes the parameters used for NCPC calculations, including the quantity and price pairs for output, demand reduction, or consumption up to the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit; the Start-Up Fee, No-Load Fee, or Interruption Cost; and the operating limits.
  - ii. In the event the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit is increased after the decision to commit the Resource, the energy price parameter for output, demand reduction, or consumption at the Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit used in making the decision to commit the Resource will be applied as the energy price parameter for additional output, demand reduction, or consumption up to the increased Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit.
  - iii. In the event a Minimum Generation Emergency is declared, the Economic Minimum Limit will be replaced with the Emergency Minimum Limit for purposes of determining the energy price parameter of the Effective Offer.
  - iv. The Effective Offer takes account of mitigation applied to the Supply Offer, whether performed prior to or after the commitment or dispatch decision is made.
  - v. The Effective Offer takes account of a reduction in the energy price parameter, the Start-Up Fee, the No-Load Fee, or the Interruption Cost in a Supply Offer or Demand Reduction Offer; or an increase in the energy price parameter of a Demand Bid that is made prior to the end of the Resource's Commitment Period.
  - vi. In the event the ISO approves the Resource's synchronization to the system as a Pool-Scheduled Resource earlier than its scheduled time, the Effective Offer takes account of the

- lesser of the energy price parameter, the Start-Up Fee and the No-Load Fee in place for the scheduled Commitment Period or the actual early release-for-dispatch time.
- vii. A Resource that is online providing synchronous condensing is considered to be in a hot temperature state for the purpose of determining the Start-Up Fee for the Effective Offer when the Resource is requested to switch from synchronous condensing to provide energy.
  - viii. The Effective Offer takes account of cost verification performed under Section III.1.9.1.
  - ix. The energy price parameter of the Effective Offer for a Demand Response Resource is the energy price parameter submitted in the Demand Reduction Offer, even where the Demand Reduction Threshold Price is used to clear the market pursuant to Section III.1.10.1A(e)(ii).

**b. Treatment of Self-Schedules.**

- i. In the Day-Ahead Energy Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to \$0, a No-Load Fee equal to \$0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to the minimum of the Energy Offer Floor and the Day-Ahead Price; or, in the case of a Storage DARD, is treated as having a Demand Bid with an energy price parameter for consumption up to its Minimum Consumption Limit equal to the maximum of the Demand Bid Cap and the Day-Ahead Price. Any amounts (MW) offered or bid above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid.
- ii. In the Real-Time Energy Market, a Resource that is committed as a Self-Schedule is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to \$0, a No-Load Fee equal to \$0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to \$0/MWh; or (ii) as having a Demand Bid for consumption up to the Minimum Consumption Limit at the Demand Bid Cap. Any amounts (MW) offered above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid. For any hour for which a Resource is dispatched pursuant to Section III.1.10.9(f), the Resource is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to \$0, a No-Load Fee equal to \$0, and an energy price parameter for output up to the requested amount at the Energy Offer Floor; or (ii) as having a Demand Bid with an energy price parameter for consumption up to the requested amount at the Energy Offer Cap.

- iii. If the Resource's Supply Offer contains a Self-Schedule for fewer contiguous hours than its Minimum Run Time, the minimum number of additional hours required to satisfy the Resource's Minimum Run Time will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market. If the Resource is committed for one or more hours immediately prior to and contiguous with the Self-Schedule, the hours of that prior Commitment Period will be counted toward satisfying the Resource's Minimum Run Time before hours subsequent to the Self-Schedule are counted. If the Resource's Supply Offer contains two Self-Schedules separated by less than the Resource's Minimum Down Time, the hours between the two Self-Schedules will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market.
- c. **Sub-Hourly Intervals.** If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.
- d. **Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Minimum Run Time or Minimum Reduction Time Carries Into Second Operating Day.** If a Resource that is committed in either (i) the Day-Ahead Energy Market, or (ii) the Reserve Adequacy Analysis prior to the start of the Operating Day must continue to operate across an Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for hour ending 24 of the Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day. If a Resource that is committed during the Operating Day must continue to operate across the Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the second Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day.
- e. **Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Committed Prior to Day-Ahead Energy Market.** If a Resource is committed for an Operating Day prior to the Day-Ahead Energy Market, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the Operating Day at the time of the commitment is used to establish the Effective Offer for the period of the commitment.
- f. **Eligibility for NCPD Credits When Performing Audits or Facility and Equipment Testing.**

The Real-Time NCPC Credit calculation for a Resource performing an audit uses the Start-Up Fee, No-Load Fee, Interruption Cost, Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction in the Effective Offer applicable to the Commitment Period during which the audit is conducted, and does not take account of any increases to the Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction that take place in the course of the audit.

Market Participants are not eligible for NCPC Credits when conducting audits or Facility and Equipment Testing under the following conditions:

- i. When a Market Participant requests that some hours of the commitment of a Pool-Scheduled Resource be used to satisfy an audit, and the Market Participant has changed the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit for those hours for the purpose of conducting the audit, the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- ii. When a Market Participant Self-Schedules a Resource to perform the audit, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the Self-Schedule and is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- iii. When a Market Participant requests that an audit be performed that requires the ISO to dispatch the Resource for the audit without advance notice to the Market Participant, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment or Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- iv. When an ISO-Initiated Claimed Capability Audit is performed pursuant to III.1.5.1.4, the Market Participant is not eligible for Real-Time Commitment NCPC Credits or Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted if both of the following are true:
  1. the Resource had a summer or winter Seasonal Claimed Capability or Seasonal DR Audit value equal to 0 MW at the beginning of the current Capability Demonstration Year, and
  2. the ISO Initiated Claimed Capability Audit is the first Claimed Capability Audit that the Resource performs during that Capability Demonstration Year.

- v. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Pool-Scheduled Resource, the Economic Minimum Limit (or Minimum Consumption Limit for a Binary Storage DARD) in place at the time of the commitment decision is used for calculating Real-Time Commitment NCPC Credits and the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.
- vi. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Resource that Self-Scheduled, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment and is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.
- g. Coordinated External Transactions are Not Eligible for NCPC and are excluded from NCPC Charges.** Notwithstanding anything to the contrary in this Appendix F, Market Participants are not eligible to receive NCPC Credits for Coordinated External Transactions purchases or sales and shall be excluded from all NCPC Charge calculations under this Appendix F.
- h. Demand Response Resource Credit Calculations.** Where indicated in Section III.F.2, the costs and revenues for a Demand Response Resource, other than those associated with Net Supply or Interruption Costs, are increased by average avoided peak distribution losses.
- i. Following Dispatch Instructions.**
  - i. For the purpose of allocating NCPC costs, a Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit greater 50 MW is considered to be following a dispatch instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 10% above its Desired Dispatch Point and not less than 10% below its Desired Dispatch Point for each interval in the hour. A Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit less than or equal to 50 MW is considered to be following a Dispatch Instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 5 MW above its Desired Dispatch Point and is not less than 5 MW below its Desired Dispatch Point for each interval in the hour. If the Resource violates this criterion in any interval during the hour, the Resource is considered to be not following Dispatch Instructions for the entire hour.

- ii. DNE Dispatchable Generators are considered to be following Dispatch Instructions if the actual output of the DNE Dispatchable Generator is at or below its Do Not Exceed Dispatch Point.

## **III.F.2. NCPC Credits**

### **III.F.2.1 Day-Ahead Energy Market NCPC Credits**

**III.F.2.1.1. Eligibility for Credit.** A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a Storage DARD with a Demand Bid that clear the Day-Ahead Energy Market in an hour is eligible for Day-Ahead Energy Market NCPC Credits for the hour.

**III.F.2.1.2. Settlement Period.** For a Generator Asset, a Demand Response Resource, or a Storage DARD, for purposes of calculating Day-Ahead Energy Market NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day for which a Resource has cleared in the Day-Ahead Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator or to or from a Fast Start Demand Response Resource, or any time a DNE Dispatchable Generator's operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation.

**III.F.2.1.3. Eligible Quantity.** For a Generator Asset, Demand Response Resource, or Storage DARD, the eligible quantity of energy is the amount of energy the Resource clears in the Day-Ahead Energy Market for each hour of the settlement period.

**III.F.2.1.3A Hourly Bid.** For a Storage DARD, the hourly bid is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each hour of the settlement period.

#### **III.F.2.1.4 Hourly Cost.**

- (a) For a Generator Asset, the hourly cost is equal to the energy price parameter for the eligible quantity, the Start-Up Fee and the No-Load Fee as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.
- (b) For a Demand Response Resource, the hourly cost is equal to the energy price parameter for the eligible quantity and the Interruption Cost as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.

(c) For a Storage DARD, the hourly cost is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity.

**III.F.2.1.4.1** For a Generator Asset or a Demand Response Resource, the Start-Up Fee or Interruption Cost is apportioned equally over the hours from the time the Resource is scheduled to begin its commitment through the end of the Commitment Period during which the Minimum Run Time or Minimum Reduction Time is scheduled to expire.

**III.F.2.1.4.2** For a Generator Asset or a Demand Response Resource, when the period of hours over which the Start-Up Fee or Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee or Interruption Cost.

**III.F.2.1.5** **Hourly Revenue.** For a Generator Asset or a Demand Response Resource, the hourly revenue is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity for the Resource.

**III.F.2.1.6** **General Credit Calculation.** Except as provided in Section III.F.2.1.7 below, the Day-Ahead Energy Market NCPC Credit for a Resource, adjusted as described in III.F.1(h), is equal to:

- (a) For a Generator Asset or a Demand Response Resource: the greater of (i) zero, and; (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly revenue for the Resource in all hours of the settlement period, where the costs and revenues of a Demand Response Resource, other than those associated with Interruption Costs, are increased by average avoided peak distribution losses; and
- (b) For a Binary Storage DARD: the greater of (i) zero and (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly bids in all hours of the settlement period.

**III.F.2.1.7** **Credit Calculation for Fast Start Generators, Flexible DNE Dispatchable Generators, Fast Start Demand Response Resources and Binary Storage DARDs Based on Daily Starts, and for Continuous Storage Generator Assets and Continuous Storage DARDs.** If either (1) the number of daily starts for a Fast Start Generator, Flexible DNE Dispatchable Generator, Fast Start Demand Response Resource or Binary Storage DARD is less than the resource's Maximum Number of Daily Starts, or (2) the resource is a Continuous Storage Generator Asset or a Continuous Storage DARD,

then the resource's Day-Ahead Energy Market NCPC Credit, adjusted as described in III.F.1(h), is calculated as follows:

- (a) For a Fast Start Generator, a Continuous Storage Generator Asset, a Flexible DNE Dispatchable Generator or a Fast Start Demand Response Resource, the Day-Ahead Energy Market NCPC Credit is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for the Resource in an hour minus the hourly revenue for the Resource in that hour.
- (b) For a Storage DARD, the Day-Ahead Energy Market NCPC Credit is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the total hourly cost for the Resource in an hour minus the total hourly bid for the Resource in that hour.

**III.F.2.2 Real-Time Energy Market NCPC Credits.** Real-Time Energy Market NCPC Credits include a Real-Time Commitment NCPC Credit, a Real-Time Dispatch NCPC Credit and a Real-Time Dispatch Lost Opportunity Cost NCPC Credit. For purposes of this Section III.F.2.2, unless otherwise expressly stated, costs and revenues shall be calculated at a five minute interval.

**III.F.2.2.1 Eligibility for Credit.**

- (a) Commitment Credits – The following Resources are eligible for Real-Time Commitment NCPC Credits for some or all intervals of the hour: (i) a Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market and that has been committed by the ISO; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; or (iii) a Binary Storage DARD with a Demand Bid that has been submitted in the Real-Time Energy Market and that has been committed by the ISO.
- (b) Dispatch Credits – The following Resources are eligible for Real-Time Dispatch NCPC Credits for some or all intervals of the hour: (i) a Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; (iii) a Storage DARD with a Demand Bid that has been submitted in the Real-Time Energy Market; or (iv) a Storage DARD that has been Postured to increase its consumption. The Real-Time Dispatch NCPC Credit shall be zero, however, if the Generator Asset has provided Regulation during the interval.
- (c) Dispatch Lost Opportunity Cost Credits – A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a Dispatchable Asset Related Demand with a Demand Bid that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Real-Time Dispatch Lost Opportunity Cost NCPC Credit; provided, however,



that such credit shall be zero if the Generator Asset, Demand Response Resource, or Dispatchable Asset Related Demand has been Postured or has provided Regulation during the interval.

### **III.F.2.2.2 Real-Time Commitment NCPC Credits**

#### **III.F.2.2.2.1 Settlement Period.**

- (a) For Generator Assets, Demand Response Resources, and Binary Storage DARDs, for purposes of calculating Real-Time Commitment NCPC Credits, a settlement period is a period of one or more contiguous intervals in an Operating Day during which a Resource is operating pursuant to one or more commitments in the Day-Ahead Energy Market or Real-Time Energy Market.
- (b) For Generator Assets and Demand Response Resources, a new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.
- (c) For Generator Assets and Binary Storage DARDs, in the event of an interruption in operation of a Resource, operation will be considered contiguous if the Resource returns to operation in accordance with the original commitment issued prior to the interruption.

#### **III.F.2.2.2.2 Eligible Quantity.**

**III.F.2.2.2.2.A** For a Binary Storage DARD, the eligible quantity for each interval is the amount of energy equal to the lesser of its Economic Dispatch Point for that interval and its Metered Quantity For Settlement for the interval.

##### **III.F.2.2.2.2.1.**

- (a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy equal to the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval; provided however, that during contiguous pricing intervals in which the Generator Asset's Economic Dispatch Point is higher than it would otherwise be as a result of an offered ramp rate limitation, then the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit

is the amount of energy for the interval equal to the lesser of: (a) the Generator Asset's Metered Quantity For Settlement; and (b) the greater of: (i) the Generator Asset's expected output level had it reduced its output per its offered ramp rate during the relevant intervals as instructed by the ISO, and (ii) the output level to which the Generator Asset would have been dispatched absent the offered ramp rate limitation.

- (b) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval, except that Metered Quantity For Settlement is used as the eligible quantity (i) when the Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) when the Resource is ramping from an offline state to be released for dispatch or (iii) after the Resource has been released for shutdown.

#### **III.F.2.2.2.2.2.**

- (a) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and its Economic Dispatch Point for the interval; provided however, that during contiguous pricing intervals in which the Demand Response Resource's Economic Dispatch Point is higher than it would otherwise be as a result of an offered ramp rate limitation, then the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy for the interval equal to the lesser of: (a) the Demand Response Resource's Metered Quantity For Settlement; and (b) the greater of: (i) the Demand Response Resource's expected demand reduction had it provided the reduction per its offered ramp rate during the relevant intervals as instructed by the ISO, and (ii) the demand reduction level at which the Demand Response Resource would have been dispatched absent the offered ramp rate limitation.
- (b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is equal to the eligible quantity used to determine interval costs pursuant to (a) above, except that the eligible quantity shall be the Metered Quantity For Settlement if any of the following are true: (i) the Demand Response Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time have

not concluded, or (iii) the Demand Response Resource has received an instruction to stop reducing demand.

#### **III.F.2.2.2.3. Interval Cost.**

- (a) The interval cost for a Generator Asset is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Start-Up Fee and No-Load Fee as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1, III.F.2.2.2.3.2, and III.F.2.2.2.3.3.
- (b) The interval cost for a Demand Response Resource is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Interruption Cost as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1 and III.F.2.2.2.3.2, provided that costs shall be set to \$0 for the interval when there is a negative demand reduction.
- (c) The interval cost for a Binary Storage DARD is the Real-Time Price for the interval multiplied by the eligible quantity. The interval cost is reduced by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval cost is also reduced by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5.

#### **III.F.2.2.2.3.1**

- (a) For a Generator Asset, the energy cost for an interval excludes the cost of (a) energy produced when the Resource is ramping from an offline state to be released for dispatch and (b) energy produced after the Resource has been released for shutdown.
- (b) For a Demand Response Resource, the energy cost for an interval excludes the cost of (a) energy produced prior to the conclusion of the Demand Response Resource Start-Up Time and (b) energy produced after the Demand Response Resource has received an instruction to stop reducing demand.

#### **III.F.2.2.2.3.2**

- (a) For a Generator Asset, the Start-Up Fee is apportioned equally over the intervals from the time the Generator Asset is released for dispatch through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire, subject to the following conditions:

- (i) The Start-Up Fee is reduced in proportion to the number of minutes after 30 the Generator Asset is released for dispatch (measured from the time the Generator Asset was scheduled to be released for dispatch), divided by the time from when the Generator Asset was scheduled to be released for dispatch through the end of the Commitment Period during which the Minimum Run Time was scheduled to expire.
  - (ii) The Start-Up Fee is excluded from the interval cost calculation if the Generator Asset is synchronized to the system prior to its scheduled synchronization time without the ISO's approval of the Generator Asset's synchronization as a Pool-Scheduled Resource.
  - (iii) The portion of the Start-Up Fee apportioned to any interval during which the Generator Asset is not online because the Generator Asset has tripped is excluded from the interval cost calculation, except in the event the Generator Asset is not online due to a trip that results from equipment failure involving equipment located on the electric network beyond the low voltage terminals of the Generator Asset's step-up transformer. It is the responsibility of the Lead Market Participant for the Generator Asset to inform the ISO at [xtrip@iso-ne.com](mailto:xtrip@iso-ne.com) within 30 days that the trip was the result of such a transmission-related event.
  - (iv) The Start-Up Fee is not reduced when the Generator Asset has shutdown with the ISO's approval prior to the end of its Commitment Period.
  - (v) The additional Start-Up Fee for a Generator Asset requested to re-start following a trip is apportioned equally over the remaining intervals of the Commitment Period when the ISO requests a Generator Asset to re-start to complete its Commitment Period.
  - (vi) When the period of intervals over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.
- (b) For a Demand Response Resource, the Interruption Cost is apportioned equally over the intervals from the time the Demand Response Resource Start-Up Time concludes through the end of the Commitment Period during which the Minimum Reduction Time is scheduled to expire, subject to the following conditions:
- (i) The Interruption Cost is reduced in proportion to the number of minutes after 30 the Demand Response Resource begins to provide a demand reduction (measured from the conclusion of the Demand Response Resource Start-Up Time), divided by the time from the conclusion of the Demand Response Resource Start-Up Time through the end of the Commitment Period during which the Minimum Reduction Time was scheduled to expire.

- (ii) The portion of the Interruption Cost apportioned to any interval during which the Demand Response Resource is not providing a demand reduction because the Demand Response Resource has become unavailable to provide a reduction is excluded from the interval cost calculation.
- (iii) The Interruption Cost is not reduced when the Demand Response Resource has stopped reducing demand with the ISO's approval prior to the end of its Commitment Period. When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.
- (iv) When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.

**III.F.2.2.2.3.3.** For a Generator Asset for each hour, the No-Load Fee is equally apportioned to each interval in the hour during the period when the Generator Asset is online following its release for dispatch and prior to its release for shutdown. The No-Load Fee is pro-rated for the hour during which the Generator Asset is released for dispatch, the hour during which the Generator Asset is released for shutdown, and any other hour during which the Generator Asset operates for less than 60 minutes.

**III.F.2.2.2.3.A Interval Bid.** The interval bid for a Binary Storage DARD is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each interval of the settlement period.

**III.F.2.2.2.4 Interval Revenue.** The interval revenue for a Generator Asset or Demand Response Resource is equal to the Real-Time Price for each interval of the settlement period multiplied by the eligible quantity for the interval. The revenue for an interval is increased by the amount by which the interval revenues in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.4 exceed the interval costs in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.3. The interval revenue is increased by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval revenue is also increased by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5. The revenues when the Generator Asset is ramping from an offline state to be released for

dispatch, or during the Demand Response Resource Start-Up Time, are apportioned equally to the intervals of the Minimum Run Time or Minimum Reduction Time.

**III.F.2.2.2.4.1.** For a Generator Asset, revenues for output up to the Resource's Economic Minimum Limit in a Self-Scheduled interval, calculated as the Real-Time Price multiplied by the output, are excluded from the revenue for the Real-Time Commitment NCPC Credit calculation.

**III.F.2.2.2.4.2.** For a Demand Response Resource, revenues shall be set to \$0 for the interval when the Locational Marginal Price is positive and there is a negative demand reduction.

**III.F.2.2.2.5 Credit Calculation for Generator Assets and Demand Response Resources.** The Real-Time Commitment NCPC Credit for a Generator Asset or a Demand Response Resource, adjusted as described in III.F.1(h) is equal to:

- (a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval revenue for the Resource for the period, plus,
- (b) For each remaining interval of the settlement period following the completion of the Minimum Run Time or Minimum Reduction Time, the greater of ((i) zero, and; (ii) the maximum potential net revenues for the Resource in the period) minus the actual net revenues for the Resource in the period, where
  - (i) The maximum potential net revenue is the maximum accumulated net interval revenue for operating and then shutting down (or, for a Demand Response Resource, reducing demand and then ceasing to reduce demand) during the period.
  - (ii) The actual net revenue is the accumulated net interval revenue over the period.
  - (iii) The net interval revenue is the interval revenues minus interval costs in the period.

**III.F.2.2.2.6. [Reserved.]**

**III.F.2.2.2.7 Credit Calculation for Binary Storage DARDs.** The Real-Time Commitment NCPC Credit for a Binary Storage DARD is equal to:

- (a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval bid for the Resource for the period,  
plus,
- (b) For each remaining interval of the settlement period following the completion of the Minimum Run Time, the greater of ((i) zero, and; (ii) the maximum potential net benefit for the Resource in the period) minus the actual net benefit for the Resource in the period, where
  - (i) The maximum potential net benefit is the maximum accumulated net interval benefit for operating and then shutting down during the period.
  - (ii) The actual net benefit is the accumulated net interval benefit over the period.
  - (iii) The net interval benefit is the interval bid minus interval cost in the period.

**III.F.2.2.2.8 Resources with Commitment in the Day-Ahead Energy Market (other than Fast Start Generators, Fast Start Demand Response Resources, and Binary Storage DARDs).**

- (a) For purposes of calculating the interval cost under Section III.F.2.2.2.3, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or Binary Storage DARD) has a commitment in the Day-Ahead Energy Market, the Start-Up Fee, No-Load Fee, Interruption Cost and energy price parameter for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to \$0 for the hour. The Start-Up Fee shall not be set to \$0 in the case when a Resource re-starts at ISO request following a trip.
- (b) For purposes of calculating the interval revenue under Section III.F.2.2.2.4, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or Binary Storage DARD) has a commitment in the Day-Ahead Energy Market, the revenue for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to \$0 for the hour if such revenue is less than \$0.
- (c) Notwithstanding anything to the contrary in this Section III.F.2.2.2, a Generator Asset that cleared in the Day-Ahead Energy Market and performs an audit scheduled by the ISO pursuant to Section III.1.5.2(f) during all or part of its Day-Ahead schedule on a higher-priced fuel than that which formed the basis of the Generator Asset's Supply Offer in the Day-Ahead Energy Market shall receive additional compensation equal to:
  - i. For the MW quantity equal to the lesser of the Generator Asset's actual metered output and Economic Dispatch Point, the difference between 1) the incremental energy audit costs based on

- the Supply Offer using the fuel on which the audit was performed and 2) amounts calculated for that same operation as reflected in the greater of the Day-Ahead Supply Offer and the cost-based Reference Levels calculated using the fuel on which the Day-Ahead Supply Offer was based; and
- ii. The difference between the No-Load Fee based on the Supply Offer using the fuel on which the audit was performed and the No-Load Fee for that same operation as reflected in the Day-Ahead Supply Offer; and
  - iii. Any additional Start-Up Fees incurred as a result of performing the audit.

### **III.F.2.2.3. Real-Time Dispatch NCPC Credits for Generator Assets and Demand Response Resources.**

#### **III.F.2.2.3.1 Settlement Period.**

- (a) Except as provided in Section III.F.2.2.3.1(b), for Generator Assets and Demand Response Resources, for purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement for a Resource are each greater than its Economic Dispatch Point, excluding any period of time when:
  - i. For a Generator Asset, the generator is ramping from an offline state to be released for dispatch, and after the generator has been released for shutdown, or
  - ii. For a Demand Response Resource, prior to the conclusion of the Demand Response Start-Up Time and after the Demand Response Resource has received a Dispatch Instruction to stop reducing demand.
- (b) For a Continuous Storage Generator Asset associated with an ATRR that has provided Regulation during the interval, a settlement period is an interval when the Desired Dispatch Point is greater than the Economic Dispatch Point.

#### **III.F.2.2.3.2. Eligible Quantity.**

##### **III.F.2.2.3.2.1.**

- (a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Generator Asset's Economic Dispatch Point for the interval subtracted from the lesser of the Generator Asset's Metered Quantity For Settlement or Desired Dispatch Point for the interval, unless a Continuous Storage Generator Asset is associated with an ATRR that has provided Regulation during the interval, in which case the eligible quantity is the



Generator Asset's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

- (b) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Demand Response Resource's Economic Dispatch Point for the interval subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement and its Desired Dispatch Point for the interval.

#### **III.F.2.2.3.2.2.**

- (a) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit is the Generator Asset's Metered Quantity For Settlement for the interval minus the Generator Asset's Economic Dispatch Point, except that the Generator Asset's Economic Dispatch Point subtracted from the lesser of the Generator Asset's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval. Notwithstanding the foregoing, if a Continuous Storage Generator Asset is associated with an ATRR that has provided Regulation during the interval, the eligible quantity is the Generator Asset's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.
- (b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit equals the Demand Response Resource's Metered Quantity For Settlement for the interval minus the Demand Response Resource's Economic Dispatch Point, except that the Demand Response Resource's Economic Dispatch Point subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval.

**III.F.2.2.3.3 Interval Cost.** For a Generator Asset or a Demand Response Resource, the interval cost is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer and does not include the Start-Up Fee, the No-Load Fee, or the Interruption Cost.

**III.F.2.2.3.4 Interval Revenue.** For a Generator Asset or a Demand Response Resource, the interval revenue is equal to the Real-Time Price multiplied by the eligible quantity.

**III.F.2.2.3.5. Credit Calculation.** For a Generator Asset or a Demand Response Resource, the Real-Time Dispatch NCPC Credit in an interval is equal to the greater of (i) zero and (ii) the interval cost minus the interval revenue for the Resource, adjusted as described in III.F.1(h).

#### **III.F.2.2.4 Real-Time Dispatch NCPC Credits for Storage DARDs**

**III.F.2.2.4.1 Settlement Period.** For purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement are each greater than the Storage DARD's Economic Dispatch Point, unless a Continuous Storage DARD is associated with an ATRR that has provided Regulation during the interval, in which case a settlement period is an interval when the Desired Dispatch Point is greater than the Economic Dispatch Point.

**III.F.2.2.4.2 Eligible Quantity.** The eligible quantity of energy is equal to the greater of (i) zero and (ii) the Storage DARD's Economic Dispatch Point for the interval subtracted from the lesser of the Storage DARD's Metered Quantity For Settlement or Desired Dispatch Point for the interval, unless a Continuous Storage DARD is associated with an ATRR that has provided Regulation during the interval, in which case the eligible quantity is the DARD's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

**III.F.2.2.4.3 Interval Cost.** The interval cost is the Real-Time Price for the interval multiplied by the eligible quantity.

**III.F.2.2.4.4 Interval Bid.** The interval bid is equal to the energy price parameter for the eligible quantity as reflected in the Demand Bid for each interval of the settlement period.

**III.F.2.2.4.5 Credit Calculation.** The Real-Time Dispatch NCPC Credit for an eligible Storage DARD in an interval is equal to the greater of: (i) zero, and; (ii) the interval cost minus the interval bid in that interval.

#### **III.F.2.2.5. Real-Time Dispatch Lost Opportunity Cost NCPC Credits**

##### **III.F.2.2.5.1. Maximum Net Revenue or Maximum Net Benefit.**

(a) For a Generator Asset or a Demand Response Resource, the maximum net revenue during the interval is the Resource's energy revenue at the Economic Dispatch Point, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point, as described in III.F.1(h).

- (b) For a Dispatchable Asset Related Demand, the maximum net benefit during the interval is the Resource's energy price parameter for the Economic Dispatch Point as reflected in the Demand Bid, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point.

**III.F.2.2.5.2. Actual Net Revenue or Actual Net Benefit.**

- (a) The actual net revenue for a Generator Asset or Demand Response Resource shall be the sum, adjusted as described in III.F.1(h), of the following two values:
- (i) for a Continuous Storage Generator Asset associated with an ATRR that has provided Regulation during the interval, the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity; otherwise, the greater of: (1) the energy revenue at the Metered Quantity For Settlement minus the offered energy cost for that quantity and (2) the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity; and
  - (ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.
- (b) The actual net benefit for a Dispatchable Asset Related Demand shall be the sum of the following two values:
- (i) for a Continuous Storage DARD associated with an ATRR that has provided Regulation during the interval, the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity; otherwise, the greater of: (1) the energy price parameter for the Metered Quantity For Settlement as reflected in the Demand Bid minus the offered energy cost for that quantity and (2) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity; and
  - (ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.

**III.F.2.2.5.3. Credit Calculation.** For a Generator Asset, a Demand Response Resource, or a Dispatchable Asset Related Demand, the Real-Time Dispatch Lost Opportunity Cost NCPC Credit is equal to the greater of: (i) zero; and (ii) the Resource's maximum net revenue or benefit for the interval less its actual net revenue or benefit for the interval.

The Dispatch Lost Opportunity Cost NCPC Credit for a Resource for an interval shall be reduced by the amount of any Rapid Response Pricing Opportunity Cost NCPC Credits for which the Resource is eligible for that interval, but shall be no less than zero.

### **III.F.2.3. Special Case NCPC Credit Calculations**

#### **III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits**

**III.F.2.3.1.1. Eligibility for Credit.** All Market Participants with pool-scheduled External Transaction imports or Increment Offers at an External Node are eligible for Day-Ahead External Transaction Import and Increment Offer NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

**III.F.2.3.1.2. Hourly Offer.** The Day-Ahead offer for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the offer price.

**III.F.2.3.1.3. Hourly Revenue.** The Day-Ahead revenue for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price.

**III.F.2.3.1.4. Credit Calculation.** A Day-Ahead External Transaction Import and Increment Offer NCPC Credit for an External Transaction import or Increment Offer, for an hour, is equal to any portion of the Day-Ahead offer in excess of the Day-Ahead revenue for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction import or Increment Offer for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction export or Decrement Bid for the same External Node and hour, the Day-Ahead External Transaction Import and Increment Offer NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction import or Increment Offer at the External Node for the hour that is not offset by the amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour. If multiple External Transaction imports or Increment Offers at an External Node are eligible for a Day-Ahead External Transaction Import and Increment Offer NCPC Credit, then for purposes of the offsetting

determination in the prior sentence External Transaction imports and Increment Offers will be offset in order from the highest to the lowest-priced transactions or offers.

### **III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits**

**III.F.2.3.2.1. Eligibility for Credit.** All Market Participants with pool-scheduled External Transaction exports or Decrement Bids at an External Node are eligible for Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

**III.F.2.3.2.2. Hourly Bid.** The Day-Ahead bid for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the bid price.

**III.F.2.3.2.3. Hourly Cost.** The Day-Ahead cost for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price at the External Node.

**III.F.2.3.2.4. Credit Calculation.** A Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for an External Transaction export or Decrement Bid, for an hour, is equal to any portion of the Day-Ahead hourly cost in excess of its Day-Ahead hourly bid for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction export or Decrement Bid for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction import or Increment Offer for the same External Node and hour, the Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour that is not offset by the amount (MW) of the total cleared External Transaction import or Increment Offer at the External Node for the hour. If multiple External Transaction exports or Decrement Bids at an External Node are eligible for a Day-Ahead External Transaction Export and Decrement Bid NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction exports and Decrement Bids will be offset in order from the lowest to the highest-priced transactions or bids.

### **III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)**

**III.F.2.3.3.1. Eligibility for Credit.** All Market Participants that submit pool-scheduled External Transactions (import or export) are eligible for Real-Time External Transaction NCPC Credits, with the exception of External Transactions to wheel energy through the New England Control Area.

**III.F.2.3.3.2. Eligible Quantity.**

- (a) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that either (i) did not clear in the Day-Ahead Energy Market, or (ii) cleared in the Day-Ahead Energy Market and the price was subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction.
- (b) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that cleared in the Day-Ahead Energy Market and the price was not subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction in excess of the cleared Day-Ahead scheduled transaction amount.

**III.F.2.3.3.3. Hourly Offer.** The hourly offer for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval offer, which is calculated by multiplying the eligible quantity by the offer price for the interval.

**III.F.2.3.3.4. Hourly Revenue.** The hourly revenue for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval revenue, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

**III.F.2.3.3.5. Hourly Bid.** The hourly bid for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval bid, which is calculated by multiplying the eligible quantity by the bid price for the interval.

**III.F.2.3.3.6. Hourly Cost.** The Real-Time cost for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval cost, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

**III.F.2.3.3.7. Credit Calculation.** A Real-Time External Transaction NCPC Credit for an External Transaction import for an hour is equal to any portion of the hourly offer in excess of the hourly revenue.

A Real-Time External Transaction NCPC Credit for an External Transaction export for an hour is equal to any portion of the hourly cost in excess of the hourly bid.

**III.F.2.3.4. [Reserved.]**

**III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits**

**III.F.2.3.5.1. Eligibility for Credit.** A Resource that is dispatched as a Synchronous Condenser is eligible for Real-Time Synchronous Condensing NCPC Credits.

**III.F.2.3.5.2. Condensing Offer Amount.** The condensing offer amount for a Resource is equal to the number of hours that the Resource is dispatched as a Synchronous Condenser in an Operating Day multiplied by the hourly price to condense as specified in the Offer Data for the Resource. For a Resource committed from an offline state to provide synchronous condensing, the condensing offer amount includes the condensing start-up fee as specified in the Offer Data for the Resource. In the event an hourly price to condense or condensing start-up fee is not included in the Offer Data for the Resource for the hours that the Resource is dispatched as a Synchronous Condenser, the value for the parameter will be zero.

**III.F.2.3.5.3. Credit Calculation.** The Real-Time Synchronous Condensing NCPC Credit for a Resource for an Operating Day is equal to the condensing offer amount for that Operating Day.

**III.F.2.3.6. Cancelled Start NCPC Credits**

**III.F.2.3.6.1. Eligibility for credit.** A Pool-Scheduled Generator Asset or Demand Response Resource is eligible for a Cancelled Start NCPC Credit if the ISO cancels its commitment of the Pool-Schedule Resource before a Generator Asset is synchronized to the New England Transmission System, or before a Demand Response Resource has completed its Demand Response Resource Notification Time, except that a Market Participant is not eligible for a credit under the following conditions:

- (a) The start is cancelled before the commencement of the Notification Time or the Demand Response Resource Notification Time;
- (b) The Resource's Notification Time or Demand Response Resource Notification Time as reflected in the Effective Offer is equal to or greater than 24 hours;

- (c) The Generator Asset is synchronized to the New England Transmission System for a Self-Schedule within the period of time equal to the lesser of its Minimum Down Time or 10 hours after receiving the ISO cancelled start order; or
- (d) The Generator Asset fails to meet its scheduled synchronization time and the ISO cancelled start order is issued more than two hours after the Resource's scheduled synchronization time.

**III.F.2.3.6.2. Credit Calculation.** The Cancelled Start NCPC Credit for a Resource is equal to the Start-Up Fee or Interruption Cost reflected in the Effective Offer multiplied by the percentage of the Notification Time or Demand Response Resource Notification Time, as reflected in the Effective Offer, that the Resource completed prior to the ISO cancelled start order, where:

- (a) The percentage of Notification Time or Demand Response Notification Time completed is equal to the number of minutes after the start of the Notification Time or Demand Response Notification Time the Resource was cancelled divided by the Notification Time or Demand Response Notification Time, and cannot exceed 100%.

#### **III.F.2.3.7. Hourly Shortfall NCPC Credits**

**III.F.2.3.7.1. Eligibility for Credit.** A Generator Asset, Demand Response Resource, or Binary Storage DARD that is pool-scheduled in the Day-Ahead Energy Market is eligible for Hourly Shortfall NCPC Credits for an hour if the ISO (1) cancels its commitment of a non-Fast Start Generator, a non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator; or (2) does not dispatch a Fast Start Generator, a Fast Start Demand Response Resource, a Binary Storage DARD, or a Flexible DNE Dispatchable Generator for the hour; and (3) either the Generator Asset or Binary Storage DARD is offline and available for operation and the Generator Asset associated with the DARD is not supplying electricity to the grid, or the Demand Response Resource has not been dispatched and is available for operation; except that (4) a Market Participant is not eligible for a credit under the following conditions:

- (a) The Resource has been Postured for all or part of the hour;
- (b) The Resource is a Limited Energy Resource that has been Postured during a prior hour in the Operating Day; or
- (c) The Resource is an Intermittent Power Resource that is not a DNE Dispatchable Generator.



**III.F.2.3.7.2. Settlement Period.** For purposes of calculating Hourly Shortfall NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is eligible for an Hourly Shortfall NCPC Credit. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.

**III.F.2.3.7.3. Eligible Quantity.** The eligible quantity for each hour of the settlement period is:

- (a) zero for a Fast Start Generator, a Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter, the Start-Up Fee and the No-Load Fee of the Supply Offer, or the total of the energy price parameter and the Interruption Cost of the Demand Reduction Offer, in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market for the hour is greater than the total of the corresponding energy price, Start-Up Fee, No Load Fee, and Interruption Cost parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;
  - i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9(e), the Start-Up Fee, No-Load Fee and energy at the Economic Minimum Limit are equal to \$0, and (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9(f), the Start-Up Fee and No-Load Fee are equal to \$0 and the energy at the requested dispatch level is the Energy Price Floor.
- (b) zero for a Binary Storage DARD in the event the energy price parameter in the Demand Bid in the Real-Time Energy Market for the consumption cleared in the Day-Ahead Energy Market for the hour is less than the energy price parameter in the Demand Bid in the Day-Ahead Energy Market for the hour.
  - i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9 (e), then the energy price at the Minimum Consumption Limit is equal to the Demand Bid Cap, and; (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9 (f), then the energy price at the requested dispatch level for Binary Storage DARDs is the Demand Bid Cap.
- (c) the Day-Ahead Economic Minimum Limit or Minimum Reduction for a non-Fast Start Generator, non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter of the Supply Offer or Demand Reduction Offer in the Real-Time Energy Market for the amount of energy cleared in the

Day-Ahead Energy Market above the Day-Ahead Economic Minimum Limit or Day-Ahead Minimum Reduction for an hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

and if neither (a) nor (b) nor (c) applies, then;

- (d) the minimum of (i) the amount of energy cleared in the Day-Ahead Energy Market for an hour and (ii) the Resource's Economic Maximum Limit, Maximum Reduction, or a Limited Energy Resource limit imposed for the hour in the Real-Time Energy Market.

**III.F.2.3.7.4. Credit Calculation (for non-Fast Start Generators, non-Fast Start Demand Response Resources, and non-Flexible DNE Dispatchable Generators).** The Hourly Shortfall NCPC Credit for a Resource, other than a Fast Start Generator, a Fast Start Demand Response Resource, a Binary Storage DARD, or a Flexible DNE Dispatchable Generator, adjusted as described in III.F.1(h), is equal to:

- (a) the greater of (i) zero and (ii) the total of (the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the Day-Ahead Economic Minimum Limit for the hour or the Day-Ahead Minimum Reduction for the hour) for all hours of the settlement period,

plus

- (b) for each hour of the settlement period, for Generator Assets, the greater of (i) zero and (ii) the product of (1) the Real-Time Price minus the Day-Ahead Price for an hour and (2) the eligible quantity minus the Day-Ahead Economic Minimum Limit for the hour; or, for Demand Response Resources, the greater of (i) zero and (ii) the product of (1) the Real Time Price minus the Day-Ahead Price for an hour and (2) the eligible quantity minus the Day-Ahead Minimum Reduction for the hour.

**III.F.2.3.7.5. Credit Calculation (for Fast Start Generators, Fast Start Demand Response Resources and Flexible DNE Dispatchable Generators).** The Hourly Shortfall NCPC Credit for a Fast Start Generator, Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and (ii) the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the eligible quantity for the hour, adjusted as described in III.F.1(h).

**III.F.2.3.7.6 Credit Calculation (for Binary Storage DARDs).** The Hourly Shortfall NCPC Credit for a Binary Storage DARD is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the Day-Ahead Price minus the Real-Time Price for an hour, multiplied by the eligible quantity for the hour.

**III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability**

**III.F.2.3.8.1. Eligibility for Credit.** A Limited Energy Resource is eligible for real-time posturing NCPC credits for any Operating Day during which the Generator Asset has been Postured, when a request to minimize the as-bid production costs of the Generator Asset has been submitted. For purposes of calculating real-time posturing NCPC credits, the Generator Asset is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Generator Asset was Postured, and if not the Generator Asset is treated as a non-Fast Start Generator. If the Generator Asset is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

**III.F.2.3.8.2. Settlement Period.** For purposes of calculating real-time posturing NCPC credits for Limited Energy Resources, a settlement period is the period of one or more contiguous hours from the initiation of Posturing through the end of the Operating Day.

**III.F.2.3.8.3 Resources Sharing a Single Fuel Source.** When Limited Energy Resources that share a fuel source are Postured, for purposes of calculating real-time posturing NCPC credits the energy available to the Postured Generator Assets will be allocated among the Postured Generator Assets sharing the fuel source as indicated by estimates of available energy provided by the Lead Market Participant for each Generator Asset prior to Posturing.

**III.F.2.3.8.4. Estimated Replacement Cost of Energy.** The estimated replacement cost of energy is (i) the average of the Day-Ahead Prices for hours ending 3 through 5 in the subsequent Operating Day for a Generator Asset that is part of an Electric Storage Facility, or (ii) the product of the oil index price multiplied by the oil-fired generator proxy heat rate for fuel oil-fired generating units, or (iii) zero for all other Generator Assets.

For fuel oil-fired generators, the oil index price is the ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation, and the oil-fired generator proxy heat rate is the average of the heat rate at Economic Min and the heat rate at Economic Max, where the heat rate at Economic Min is, for a Generator Asset, the average hourly energy price parameter of the Supply Offer at the Generator Asset's Economic Minimum Limit at the time of the Posturing decision divided by the oil index price, and the heat rate at Economic Max is, for a Generator Asset, the average hourly energy price parameter of the Supply Offer at the Generator Asset's Economic Maximum Limit at the time of the Posturing decision divided by the oil index price.

**III.F.2.3.8.5. Estimated Revenue.** The estimated revenue for a Generator Asset is the optimized energy output multiplied by the Real-Time Price for all hours in the settlement period. The optimized energy output is estimated for each hour by allocating the Postured energy to hours that the Generator Asset would have operated had it not been Postured based on Real-Time Prices in the Operating Day, subject to the following conditions:

- (a) the optimized energy output determination will take account of the Generator Asset's Economic Minimum Limit, and Economic Maximum Limit.
- (b) the optimized energy output determination will take account of the estimated avoided cost of replacing energy that is not allocated to any hour and remains available at the end of the Operating Day.
- (c) for non-Fast Start Generators, the optimized energy output is calculated for the contiguous hours from the time the Generator Asset is Postured until the available energy is depleted.

**III.F.2.3.8.6. Estimated Avoided Replacement Cost.** The estimated avoided replacement cost for an Operating Day is the remaining energy that would have been available at the end of the Operating Day had the Generator Asset operated in accordance with the optimized energy output determination in Section III.F.2.3.8.5, plus any increase in the remaining energy resulting from replenishment during the Operating Day after the Generator Asset is Postured, multiplied by the estimated replacement cost of energy.

**III.F.2.3.8.7. Actual Revenue.** The actual revenue for a Generator Asset is the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the settlement period.

**III.F.2.3.8.8. Actual Avoided Replacement Cost.** The actual avoided replacement cost for an Operating Day is the actual remaining energy at the end of the Operating Day multiplied by the estimated replacement cost of energy.

**III.F.2.3.8.9. Credit Calculation.** The real-time posturing NCPC credit for Limited Energy Resources is equal to the greater of (i) zero and (ii) the estimated revenue plus the estimated avoided replacement cost, minus the actual revenue plus the actual avoided replacement cost.

**III.F.2.3.9. Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured for Reliability and for Demand Response Resources Postured for Reliability**

**III.F.2.3.9.1. Eligibility for Credit.** Generator Assets (other than Limited Energy Resources) and Demand Response Resources are eligible for real-time posturing NCPC credits for the hours during which the Resource has been Postured.

**III.F.2.3.9.2. Settlement Period.** For purposes of calculating real-time posturing NCPC credits, a settlement period is an hour during which the Generator Asset or Demand Response Resource is Postured.

**III.F.2.3.9.3. Offer Used for Estimated Hourly Revenue and Cost.**

- (a) For a Generator Asset, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:
  - (i) Energy Price: the higher of the energy price parameter specified in (1) the Supply Offer for the hour at the time the ISO Postures the Generator Asset, or (2) the Supply Offer for the hour at the start of the hour;
  - (ii) Start-Up Fee and No Load Fee: for Generator Assets Postured offline, the Start-Up Fee and No-Load Fee specified in the Supply Offer for the hour at the time the Generator Asset is Postured;
  - (iii) for Generator Assets Postured to remain online but reduce output, the Start-Up Fee and No-Load Fee are calculated pursuant to Section III.F.2.2.2.3.
- (b) For a Demand Response Resource, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:

- (i) Energy Price: the higher of the energy price parameter specified in (1) the Demand Reduction Offer for the hour at the time the ISO Postures the Resource, or (2) the Demand Reduction Offer for the hour at the start of the hour;
- (ii) Interruption Cost: for a Demand Response Resource Postured to a demand reduction of zero MW, the Interruption Cost specified in the Demand Reduction Offer for the hour at the time the Demand Response Resource is Postured; for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MW, the Interruption Cost is calculated pursuant to Section III.F.2.2.2.3.

#### **III.F.2.3.9.4. Estimated Hourly Revenue.**

- (a) The estimated hourly revenue for a Generator Asset is the optimized energy output multiplied by the Real-Time Price for the hour. The optimized energy output is estimated for each hour by determining where the Generator Asset would have operated had it not been Postured based on Real-Time Prices. The optimized energy output determination will take account of the energy price parameter of the Supply Offer and the Generator Asset's Economic Minimum Limit and Economic Maximum Limit.
- (b) The estimated hourly revenue for a Demand Response Resource is the optimized demand reduction multiplied by the Real-Time Price for the hour, where:
  - (i) The optimized demand reduction is estimated for each hour by determining where the Demand Response Resource would have operated had it not been Postured based on Real-Time Prices. The optimized demand reduction determination will take account of the energy price parameter of the Demand Reduction Offer and the Demand Response Resource's Minimum Reduction and Maximum Reduction.

#### **III.F.2.3.9.5. Estimated Hourly Cost.**

- (a) The estimated hourly cost for a Generator Asset is the energy price parameter of the Supply Offer for the optimized energy output for the hour, plus the Start-Up Fee and the No-Load Fee, subject to the following conditions:
  - (i) For a Fast Start Generator Postured offline, the Start-Up Fee is included in each hour's cost and is not subject to apportionment;
  - (ii) For a non-Fast Start Generator Postured offline, the Start-Up Fee is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.
- (b) The estimated hourly cost for a Demand Response Resource is the energy price parameter of the Demand Reduction Offer for the optimized demand reduction for the hour (where optimized demand

reduction is determined pursuant to Section III.F.2.3.9.4(b)), plus the Interruption Cost, subject to the following conditions:

- (i) For a Fast Start Demand Response Resource Postured to a demand reduction level of zero MW, the Interruption Cost is included in each hour's cost and is not subject to apportionment;
  - (ii) For a non-Fast Start Demand Response Resource Postured to a demand reduction of greater than zero MW, the Interruption Cost is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.
- (c) A Generator Asset is treated as a Fast Start Generator and a Demand Response Resource is treated as a Fast Start Demand Response Resource for purposes of determining the estimated hourly cost only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator or non-Fast Start Demand Response Resource. If at the time the Resource is Postured the Generator Asset is offline, or the Demand Response Resource has not been dispatched, then its designation as a Fast Start Generator or Fast Start Demand Response Resource is determined as of the time of the Posturing decision.

**III.F.2.3.9.6. Actual Hourly Revenue.** The actual hourly revenue for a Generator Asset or a Demand Response Resource is the sum of the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the hour.

**III.F.2.3.9.7. Actual Hourly Cost.**

- (a) The actual hourly cost for a Generator Asset Postured to remain online but reduce output is the sum of the interval cost, which is the energy price parameter of the Supply Offer for the Metered Quantity For Settlement for the interval, plus the Start-Up Fee and No-Load Fee calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Generator Asset Postured offline is zero.
- (b) The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MW is the sum of the interval cost, which is the energy price parameter of the Demand Reduction Offer for the Metered Quantity For Settlement for the interval, plus the Interruption Cost calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to zero MW is zero.

**III.F.2.3.9.8. Credit Calculation.** The real-time posturing NCPC credit for a Generator Asset (other than a Limited Energy Resource) or a Demand Response Resource is equal to the greater of (i) zero and

(ii) the estimated hourly revenue minus the estimated hourly cost, minus the actual hourly revenue minus actual hourly cost, adjusted as described in III.F.1(h).

### **III.F.2.3.10. Rapid Response Pricing Opportunity Cost NCPC Credits Resulting from Commitment of Rapid Response Pricing Assets**

**III.F.2.3.10.1. Eligibility for Credit.** During any five-minute pricing interval in which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, any Resource that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Rapid Response Pricing Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Resource is non-dispatchable; the Resource has been Postured or has provided Regulation during the interval; if the Resource is a Settlement Only Resource, or if the Resource is an External Resource or External Transaction.

### **III.F.2.3.10.2. Economic Net Revenue or Economic Net Benefit.**

- (a) The economic net revenue for a Generator Asset or Demand Response Resource during the pricing interval is the Resource's optimized feasible energy quantity multiplied by the Real-Time Price, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.
- (b) The economic net benefit for a Dispatchable Asset Related Demand during the pricing interval is the Resource's energy price parameter for its optimized feasible energy quantity as reflected in its Demand Bid, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the optimized feasible energy quantity multiplied by the Real-Time Price.
- (c) The optimized feasible energy and reserve quantities are determined consistent with the Resource's offer or bid parameters, and are the energy and reserve quantities that maximize the Resource's economic net revenue or economic net benefit for the pricing interval, without changing the Resource's commitment status.

### **III.F.2.3.10.3. Actual Net Revenue or Actual Net Benefit.**

- (a) Except as provided in Section III.F.2.3.10.3(b), the actual net revenue for a Generator Asset or Demand Response Resource is the greater of: (i) the actual energy quantity supplied during the pricing interval multiplied by the Real-Time Price, plus the actual reserve quantity supplied during the pricing interval multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities; and (ii) the dispatched energy quantity multiplied by the Real-Time Price,



plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

- (b) The actual net revenue for a Generator Asset associated with an ATRR that has provided Regulation during the interval is equal to the dispatched energy quantity multiplied by the Real-Time Price, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.
- (c) Except as provided in Section III.F.2.3.10.3(d), the actual net benefit for a Dispatchable Asset Related Demand is the greater of: (i) the energy price parameter for the actual energy quantity consumed as reflected in the Demand Bid, plus the actual reserve quantity supplied multiplied by the Real-Time Reserve Clearing Price, minus the actual energy quantity consumed multiplied by the Real-Time Price, and (ii) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.
- (d) The actual net revenue for a DARD associated with an ATRR that has provided Regulation during the interval is equal to the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.

**III.F.2.3.10.4. Credit Calculation.** The real-time Rapid Response Pricing Opportunity Cost NCPC Credit for a Resource is equal to the greater of: (i) zero; and (ii) the Resource's economic net revenue or economic net benefit for the interval less its actual net revenue or actual net benefit for the pricing interval.

**III.F.2.4. Apportionment of NCPC Credits.** For purposes of this Section III.F.2.4, any values previously established at the five minute level shall be aggregated to create hourly values.

Each Day-Ahead Energy Market NCPC Credit calculated pursuant to III.F.2.1.6 is apportioned to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue for all hours in the settlement period.

Each Real-Time Commitment NCPC Credit is apportioned as follows: (i) for the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the portion of the Commitment

Period, and (ii) for all remaining intervals of the settlement period, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the period.

Each Hourly Shortfall NCPC Credit for a non-Fast Start Generator, a non-Fast Start Demand Response Resource or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator for energy cleared in the Day-Ahead Energy Market at the Resource's Economic Minimum Limit or Minimum Reduction is apportioned to the hours in which the Real-Time Price exceeds the Day-Ahead Price, for all hours in the settlement period.

The following NCPC credits are assigned to the hours for which the credit was calculated:

- Day-Ahead Energy Market NCPC Credits calculated pursuant to Section III.F.2.1.7.
- Real-Time Dispatch Lost Opportunity Cost NCPC Credits,
- Real-Time Dispatch NCPC Credits for all Resources,
- Day-Ahead External Transaction Import and Increment Offer NCPC Credits,
- Day-Ahead External Transaction Export and Decrement Bid NCPC Credits,
- Real-Time External Transaction NCPC Credits,
- Hourly Shortfall NCPC Credits for Fast Start Generators, Fast Start Demand Response Resources, Binary Storage DARDs and Flexible DNE Dispatchable Generators,
- Hourly Shortfall NCPC Credits for non-Fast Start Generators, non-Fast Start Demand Response Resources, and DNE Dispatchable Generators that are not Flexible DNE Dispatchable Generators for energy cleared in the Day-Ahead Energy Market above the Resource's Economic Minimum Limit or Minimum Reduction, and
- Rapid Response Pricing Opportunity Cost NCPC Credits as described in Section III.F.2.3.10.

**III.F.2.5. NCPC Credit Designation for Purposes of NCPC Cost Allocation.** Each hourly credit for Day-Ahead Energy Market NCPC Credits, Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, Day-Ahead External Transaction Import and Increment Offer NCPC Credits, Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, Real-Time External Transaction NCPC Credits, Hourly Shortfall NCPC Credits, and Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured For Reliability and Demand Response Resources Postured For Reliability, and each daily credit for Real-Time Synchronous Condensing NCPC Credits, Cancelled Start NCPC Credits, Real-

Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability, and Rapid Response Pricing Opportunity Cost NCPC Credit is designated as first contingency, second contingency, voltage (VAR), distribution (SCR), ISO initiated audits and Minimum Generation Emergency consistent with the reason provided by the ISO when issuing a Dispatch Instruction for the Resource. If there is more than one reason provided by the ISO when issuing the Dispatch Instruction, the NCPC Credits are divided equally for purposes of the above designations. With the exception of Day-Ahead External Transaction Import and Increment Offer NCPC Credits and Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, the hourly credits are summed to determine the total credits for each NCPC Charge category for a day.

### **III.F.3. Charges for NCPC**

#### **III.F.3.1. Cost Allocation.**

**III.F.3.1.1 Day-Ahead Energy Market NCPC Cost Allocation.** NCPC costs for the Day-Ahead Energy Market are allocated and charged as follows:

- (a) The total NCPC cost for the Day-Ahead Energy Market associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.
- (b) The total NCPC cost for the Day-Ahead Energy Market for resources designated as Special Constraint Resources in the Day-Ahead Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.
- (c) The total NCPC cost for the Day-Ahead Energy Market for resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.
- (d) For each External Node, the total NCPC cost for Day-Ahead External Transaction Import and Increment Offer NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Load Obligations at the External Node for the hour.
- (e) For each External Node, the total Day-Ahead External Transaction Export and Decrement Bid NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Generation Obligations at the External Node for the hour.

- (f) All remaining NCPC costs for the Day-Ahead Energy Market (except the NCPC costs for Storage DARDs) are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub).
- (g) All remaining NCPC costs for the Day-Ahead Energy Market associated with Storage DARDs are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub) excluding Day-Ahead Load Obligations associated with Storage DARDs.

**III.F.3.1.2. Real-Time Energy Market NCPC Cost Allocation.** NCPC costs for the Real-Time Energy Market are allocated and charged as follows, subject to the conditions in Section III.F.3.1.3:

- (a) The total NCPC cost for the Real-Time Energy Market associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are allocated and charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.
- (b) The total NCPC cost for the Real-Time Energy Market for resources designated as Special Constraint Resources in the Real-Time Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.
- (c) The total ISO initiated audit NCPC cost for resources performing an ISO initiated audit is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.
- (d) The total NCPC cost for resources being Postured in the Real-Time Energy Market is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.
- (e) The total NCPC cost for Rapid Response Pricing Opportunity Cost NCPC Credit during pricing intervals in which one or more Rapid Response Pricing Asset is committed in the Real-Time Energy Market (and not Self-Scheduled) is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.
- (f) The total NCPC cost for the Real-Time Energy Market for resources identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.
- (g) Total Minimum Generation Emergency Credits within a Reliability Region are allocated and charged hourly to Market Participants based on each Market Participant's pro rata share of Real-Time

Generation Obligations, and positive Real-Time Demand Reduction Obligations, excluding that portion of a Market Participant's Real-Time Generation Obligation and Real-Time Demand Reduction Obligation within a Reliability Region that is eligible for a Real-Time Dispatch NCPC Credit pursuant to Section III.F.2.2.3 during a Minimum Generation Emergency.

- (h) The total NCPC cost for Real-Time Dispatch Lost Opportunity Cost NCPC Credits is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.
- (i) All remaining NCPC costs for the Real-Time Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of the absolute values of a Market Participant's (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day (excluding certain positive Real-Time Load Obligation Deviations as described in Section III.F.3.1.3(d)); (ii) generation deviations for Pool-Scheduled Resources not following Dispatch Instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following Dispatch Instructions, and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following Dispatch Instructions, including External Resources, in MWhs during the Operating Day; (iii) demand reduction deviations for Pool-Scheduled Demand Response Resources not following Dispatch Instructions; and (iv) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day. The Real-Time deviations calculation is specified in greater detail in Section III.F.3.2.

### **III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation.**

- (a) If a Generator Asset has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.
- (b) If a Demand Response Resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the resource should not be dispatched in order to avoid a Minimum Generation Emergency, the Market Participant will be responsible for all Real-Time Demand Reduction Obligation Deviation charges, but will not incur related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.
- (c) Any difference between the actual consumption (Real-Time Load Obligation) of a DARD and the DARD's Demand Bids that clear in the Day-Ahead Energy Market that result from operation in

accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation for the purpose of allocating costs for Real-Time Energy Market NCPC Credits.

- (d) In any hour during which a Capacity Scarcity Condition occurs or ISO New England Operating Procedure No. 4 or ISO New England Operating Procedure No. 7 are implemented, any NCPC Charges that would have been allocated pursuant to Section III.F.3.2 to net positive Real-Time Load Obligation Deviations in an affected Load Zone (and related portion of adjacent External Nodes) are instead allocated and charged to Market Participants based on their pro rata share of the sum of their Real-Time Load Obligation (excluding Real-Time Load Obligations associated with a Postured Dispatchable Asset Related Demand Resource) in all the affected Load Zones and (and related portion of adjacent External Nodes) during the affected hour(s). For purposes of this calculation, the ISO shall apportion any Real-Time Load Obligations and Real-Time Load Obligation Deviations at an External Node equally among the Load Zones to which the External Node is interconnected.

### **III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits.**

Each Market Participant's pro-rata share of the Real-Time deviations for Real-Time Energy Market NCPC Credits is the following:

- (a) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

- (b) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) or

(Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

- (c) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

**plus,**

- (d) for each Pool-Scheduled Generator Asset and Continuous Storage Generator Asset:

- (i) If the Generator Asset is not following Dispatch Instructions, has cleared Day-Ahead, has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – Desired Dispatch Point) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

- (ii) If the Generator Asset is not following Dispatch Instructions, has cleared Day-Ahead, has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – cleared Day-Ahead MWh) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

**plus,**

(e) for each Pool-Scheduled Demand Response Resource:

- (i) If the Demand Response Resource is being dispatched, is not following Dispatch Instructions, has cleared Day-Ahead, and has not been ordered to stop reducing demand for reliability purposes: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction – Desired Dispatch Point) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

- (ii) If the Demand Response Resource is unavailable and has cleared Day-Ahead: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction – cleared Day-Ahead MWh) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

**plus,**

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation,

where

- (i) each Market Participant's Real-Time Load Obligation Deviation for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub), and
- (ii) for purposes of calculating a Participant's Real-Time Load Obligation Deviation under this subsection (e), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and
- (iii) External Transaction sales curtailed by the ISO are omitted from this calculation.

**plus,**



(g) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation,

where

- (i) each Market Participant's Real-Time Generation Obligation Deviation at External Nodes for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes, and
- (ii) for purposes of calculating a Participant's Real-Time Generation Obligation Deviation under this sub-section (f), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and
- (iii) External Transaction purchases curtailed by the ISO are omitted from this calculation.

**plus,**

(h) the absolute value of the total over all Locations of the Market Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

### **III.F.3.3 Local Second Contingency Protection Resource NCPC Charges.**

Each Market Participant's pro-rata share of the cost for Day-Ahead Energy Market NCPC Credits and Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection is based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region, excluding Real-Time Load Obligations associated with Storage DARDs subject to the following conditions:

- (a) The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating a Market Participant's pro-rata

share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

- (b) For hours in which there is an NCPC cost for a resource providing Local Second Contingency Protection and ISO is selling Emergency Energy to an adjacent Control Area, the scheduled amount of Emergency Energy at the applicable External Node will be included in the calculation of a Market Participant’s pro rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection as if the Emergency Energy sale were a Real-Time Load Obligation within each affected Reliability Region. The pro rata share calculated for the Emergency Energy transaction shall be included in the charges under an agreement for purchase and sale of Emergency Energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency Energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

<b>External Node Common Name</b>	<b>Associated Transmission Facilities</b>	<b>Reliability Region(s)</b>	<b>Allocator</b>
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390/3016) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-7 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bears Swamp Line (E205W Line)	Vermont, Vermont Vermont West Central Massachusetts	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described

<b>External Node Common Name</b>	<b>Associated Transmission Facilities</b>	<b>Reliability Region(s)</b>	<b>Allocator</b>
	Alps – Berkshire Line (393Line)  Pleasant Valley – Long Mountain Line (398 Line)	West Central Massachusetts  Connecticut	in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
NY NNC External Node	Northport-Norwalk Harbor (601,602 and 603 Lines)	Connecticut	100% to Connecticut
NY CSC External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(c) For each month, the ISO performs an evaluation of total Local Second Contingency Protection Resource NCPC Charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph c, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency Energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Storage DARD.

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge  $_{(Reliability\ Region, month)}$  > .06 X Load Weighted Real-Time LMP  $_{(Reliability\ Region, month)}$

Condition 2 – is the Local Second Contingency Protection Resource Charge %  $_{(Reliability\ Region, month)}$  > 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge %  $_{(Reliability\ Region)}$

Where:

Real-Time Load Obligation (Reliability Region, month) equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge (Reliability Region, month) equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation (Reliability Region, month).

Load Weighted Real-Time LMP (Reliability Region, month) equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation (Reliability Region, month).

Local Second Contingency Protection Resource Charge % (Reliability Region, month) equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP (Reliability Region, month).

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % (Reliability Region) equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge % (Reliability Region, month) divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % (Reliability Region), a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % (Reliability Region) value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge (Reliability Region, month) is triggered.

- (ii) Determination of the portion of Local Second Contingency Protection Resource Charge (Reliability Region, month) to be reallocated –

Local Second Contingency Protection Resource Charge (Reliability Region, month) to be reallocated =  
Real-Time Load Obligation (Reliability Region, month) X Min (Condition 1 Rate (Reliability Region, month),  
Condition 2 Rate (Reliability Region, month))

Where:

Condition 1 Rate  $_{(Reliability\ Region, month)}$  equals the Local Second Contingency Protection Resource Charge  $_{(Reliability\ Region, month)}$  minus .06 times the Load Weighted Real-Time LMP  $_{(Reliability\ Region, month)}$ .

Condition 2 Rate  $_{(Reliability\ Region, month)}$  equals the Local Second Contingency Protection Resource Charge  $_{(Reliability\ Region, month)}$  minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge  $\%_{(Reliability\ Region)}$  times the Load Weighted Real-Time LMP  $_{(Reliability\ Region, month)}$ .

(iii) Determination of Local Second Contingency Protection Resource Charge  $_{(Reliability\ Region, month)}$  reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

$(Real-Time\ Load\ Obligation_{(Participant, Reliability\ Region, month)} / Real-Time\ Load\ Obligation_{(Reliability\ Region, month)}) * Local\ Second\ Contingency\ Protection\ Resource\ Charges_{(Reliability\ Region, month)}$  to be reallocated

Where:

Real-Time Load Obligation  $_{(Participant, Reliability\ Region, month)}$  equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

$(Regional\ Network\ Load_{(Transmission\ Customer, Reliability\ Region, month)} / Regional\ Network\ Load_{(Reliability\ Region, month)}) * Local\ Second\ Contingency\ Protection\ Resource\ Charges_{(Reliability\ Region, month)}$  to be reallocated

Where:

Regional Network Load  $_{(Reliability\ Region, month)}$  equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load (Customer, Reliability Region, month) equals:

The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

#### **III.F.4. NCPC Reporting**

**III.F.4.1. Zonal NCPC Report.** Beginning January 2019, for each month, no later than 20 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating the aggregate dollar amount of NCPC Credits by category paid to the resources located in each Load Zone for each day during that month.

**III.F.4.2. Resource-Specific NCPC Report.** Beginning January 2019, for each month, no later than 90 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating the name of each resource that received NCPC Credits for that month and the total dollar amount of NCPC Credits that each of those resources received for that month.

**III.F.4.3. Operator-Initiated Commitment Report.** Beginning January 2019, for each month, no later than 30 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating each resource commitment made during that month after the Day-Ahead Energy Market for a reason other than minimizing the total production costs of serving load. For each such commitment, the report shall include the start time, the Economic Maximum Limit or Maximum Reduction of the committed resource, the Load Zone in which the committed resource is located, and the reason for the commitment.

## **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:

**Active Demand 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.

**Actual Capacity Provided** is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

**Actual Load** is the consumption at the Retail Delivery Point for the hour.

**Additional Resource Blackstart O&M Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Additional Resource Specified-Term Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Additional Resource Standard Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Administrative Costs** are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.



**Administrative Export De-List Bid** is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

**Administrative Sanctions** are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

**ADR Neutrals** are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

**Advance** is defined in Section IV.A.3.2 of the Tariff.

**Affected Party**, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

**Affiliate** is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

**AGC** is automatic generation control.

**AGC SetPoint** is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

**AGC SetPoint Deadband** is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

**Allocated Assessment** is a Covered Entity's right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

**Alternative Dispute Resolution (ADR)** is the procedure set forth in Appendix D to Market Rule 1.

**Alternative Technology Regulation Resource (ATTR)** is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

**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.

**Annual Reconfiguration Transaction** is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

**Applicants**, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

**Application** is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

**Asset** is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

**Asset Registration Process** is the ISO business process for registering an Asset.

**Asset Related Demand** is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration

Process, and is made up of either: (1) 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 or (2) one or more storage facilities with an aggregate consumption capability of at least 1 MW.

**Asset Related Demand Bid Block-Hours** are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of “unavailable” for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of “available,” the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

**Asset-Specific Going Forward Costs** are the net costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

**Assigned Meter Reader** reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

**Auction Revenue Right (ARR)** is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

**Auction Revenue Right Allocation (ARR Allocation)** is defined in Section 1 of Appendix C of Market Rule 1.

**Auction Revenue Right Holder (ARR Holder)** is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

**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 Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

**Average Hourly Load Reduction** is either: (i) the sum of the On-Peak 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; or (ii) the sum of the Seasonal Peak 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. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the 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 On-Peak 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; or (ii) the sum of the Seasonal Peak 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. Electrical energy output and Average Hourly Output shall be determined consistent with the 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.13.7.1.2.2 of Market Rule 1.

**Backstop Transmission Solution** is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

**Bankruptcy Code** is the United States Bankruptcy Code.

**Bankruptcy Event** occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

**Bilateral Contract (BC)** is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

**Bilateral Contract Block-Hours** are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

**Binary Storage DARD** is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Binary Storage Facility** is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**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 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 Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

**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.

**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 established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

**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).

**Block** is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

**Block-Hours** are the number of Blocks administered for a particular hour.

**Budget and Finance Subcommittee** is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

**Business Day** is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

**Cancelled Start NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Capability Demonstration Year** is the one year period from September 1 through August 31.

**Capacity Acquiring Resource** is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

**Capacity Balancing Ratio** is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

**Capacity Base Payment** is the portion of revenue received in the Forward Capacity Market as described in Section III.13.7.1 of Market Rule 1.

**Capacity Capability Interconnection Standard** has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

**Capacity Clearing Price** is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

**Capacity 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 as described in Section III.13.7.5.2 of Market Rule 1.

**Capacity Load Obligation Acquiring Participant** is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

**Capacity Network Import Capability (CNI Capability)** is as defined in Section I of Schedule 25 of the OATT.

**Capacity Network Import Interconnection Service (CNI Interconnection Service)** is as defined in Section I of Schedule 25 of the OATT.



**Capacity Load Obligation Bilateral** is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

**Capacity Load Obligation Transferring Participant** is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

**Capacity Network Resource (CNR)** is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

**Capacity Network Resource Interconnection Service (CNR Interconnection Service)** is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

**Capacity Performance Bilateral** is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 of Market Rule 1.

**Capacity Performance Payment** is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1.

**Capacity Performance Payment Rate** is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 of Market Rule 1.

**Capacity Performance Score** is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 of Market Rule 1.

**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 Scarcity Condition** is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

**Capacity Scarcity Condition** is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 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 Transfer Rights (CTRs)** are calculated in accordance with Section III.13.7.5.4.

**Capacity Transferring Resource** is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

**Capacity Zone** is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

**Capacity Zone Demand Curves** are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

**Capital Funding Charge (CFC)** is defined in Section IV.B.2 of the Tariff.

**CARL Data** is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

**Category B Designated Blackstart Resource** has the same meaning as 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 or the demand reduction capability of a Demand Response Resource.

**Cluster Enabling Transmission Upgrade (CETU)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Entry Deadline** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Cluster Interconnection System Impact Study (CSIS)** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Clustering** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**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 Capacity Commitment Period, 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. 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** is capacity that has achieved FCM Commercial Operation.

**Commission** is the Federal Energy Regulatory Commission.

**Commitment Period** is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

**Common Costs** are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

**Completed Application** is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

**Compliance Effective Date** is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

**Composite FCM Transaction** is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

**Conditional Qualified New Resource** is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

**Confidential Information** is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

**Confidentiality Agreement** is Attachment 1 to the ISO New England Billing Policy.

**Congestion** is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different

from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

**Congestion Component** is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

**Congestion Cost** is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

**Congestion Paying LSE** is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

**Congestion Revenue Fund** is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

**Congestion Shortfall** means congestion payments exceed congestion charges during the billing process in any billing period.

**Continuous Storage ATRR** is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage DARD** is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage Generator Asset** is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**Continuous Storage Facility** is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**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.

**Controllable Behind-the-Meter Generation** means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

**Coordinated External Transaction** is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.

**Coordinated Transaction Scheduling** means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

**Correction Limit** means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

**Cost of Energy Consumed (CEC)** is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

**Cost of Energy Produced (CEP)** is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

**Cost of New Entry (CONE)** is the estimated cost of new entry (\$/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

**Counterparty** means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

**Covered Entity** is defined in the ISO New England Billing Policy.

**Credit Coverage** is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

**Credit Qualifying** means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

**Credit Threshold** consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

**Critical Energy Infrastructure Information (CEII)** is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

**Current Ratio** is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

**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) of Market Rule 1.

**Day-Ahead Congestion Revenue** is defined in Section III.3.2.1(i) of Market Rule 1.

**Day-Ahead Demand Reduction Obligation** is defined in Section III.3.2.1(a) of Market Rule 1.

**Day-Ahead Energy Market** means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, 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.

**Day-Ahead Energy Market Congestion Charge/Credit** is defined in Section III.3.2.1(f) of Market Rule 1.



**Day-Ahead Energy Market Energy Charge/Credit** is defined in Section III.3.2.1(f) of Market Rule 1.

**Day-Ahead Energy Market Loss Charge/Credit** is defined in Section III.3.2.1(f) of Market Rule 1.

**Day-Ahead Energy Market NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Day-Ahead External Transaction Export and Decrement Bid NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Day-Ahead External Transaction Import and Increment Offer NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Day-Ahead Generation Obligation** is defined in Section III.3.2.1(a) of Market Rule 1.

**Day-Ahead Load Obligation** is defined in Section III.3.2.1(a) of Market Rule 1.

**Day-Ahead Locational Adjusted Net Interchange** is defined in Section III.3.2.1(a) of Market Rule 1.

**Day-Ahead Loss Charges or Credits** is defined in Section III.3.2.1(k) of Market Rule 1.

**Day-Ahead Loss Revenue** is defined in Section III.3.2.1(j) of Market Rule 1.

**Day-Ahead Prices** means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

**DDP Dispatchable Resource** is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

**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 Capacity Resource** means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

**Demand Designated Entity** is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

**Demand Reduction Offer** is an offer by a Market Participant with a Demand Response Resource to reduce demand.

**Demand Reduction Offer Block-Hours** are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be

totaled to determine the quantity of Demand Reduction 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 Demand Reduction 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 Demand Reduction Offer Block-Hours.

**Demand Reduction Threshold Price** is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

**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 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 Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

**Demand Response Asset** is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

**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 as determined pursuant to Section III.8.2.

**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 DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

**Demand Response Resource Notification Time** is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts 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 period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

**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, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

**Designated Entity** is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset 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)** means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

**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 Response Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

**Dispatch Zone** means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

**Dispatchable Asset Related Demand (DARD)** is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, 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 Operating Procedures and Manuals.

**Dispatchable Resource** is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

**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 directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

**DRR Aggregation Zone** is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

**Do Not Exceed (DNE) Dispatchable Generator** is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

**Do Not Exceed Dispatch Point** is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

**Dynamic De-List Bid** is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

**Dynamic De-List Bid Threshold** is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

**EA Amount** is defined in Section IV.B.2.2 of the Tariff.

**Early Amortization Charge (EAC)** is defined in Section IV.B.2 of the Tariff.

**Early Amortization Working Capital Charge (EAWCC)** is defined in Section IV.B.2 of the Tariff.

**Early Payment Shortfall Funding Amount (EPSF Amount)** is defined in Section IV.B.2.4 of the Tariff.

**Early Payment Shortfall Funding Charge (EPSFC)** is defined in Section IV.B.2 of the Tariff.

**EAWW Amount** is defined in Section IV.B.2.3 of the Tariff.

**EBITDA-to-Interest Expense Ratio** is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent

fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

**Economic Dispatch Point** is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

**Economic Maximum Limit or Economic Max** is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

**Economic Minimum Limit or Economic Min** is (a) for a Generator Asset 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 a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

**Economic Study** is defined in Section 4.1(b) of Attachment K to the OATT.



**Effective Offer** is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

**EFT** is electronic funds transfer.

**Elective Transmission Upgrade** is defined in Section I of Schedule 25 of the OATT.

**Elective Transmission Upgrade Interconnection Customer** is defined in Schedule 25 of the OATT.

**Electric Reliability Organization (ERO)** is defined in 18 C.F.R. § 39.1.

**Electric Storage Facility** is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

**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 output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

**EMS** is energy management system.

**End-of-Round Price** is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

**End User Participant** is defined in Section 1 of the Participants Agreement.

**Energy** is power produced in the form of electricity, measured in kilowatthours or megawatthours.

**Energy Administration Service (EAS)** is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

**Energy Component** means the Locational Marginal Price at the reference point.

**Energy Efficiency** is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

**Energy Imbalance Service** is the form of Ancillary Service described in Schedule 4 of the OATT.

**Energy Market** is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

**Energy Non-Zero Spot Market Settlement Hours** are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation 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, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

**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, a Market Participant's share of Zonal Capacity Obligation 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.

**Excepted Transaction** is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

**Existing Capacity Qualification Deadline** is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

**Existing Capacity Qualification Package** is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

**Existing Capacity Resource** is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

**Existing Capacity Retirement Deadline** is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

**Existing Capacity Retirement Package** is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

**Existing Demand Capacity Resource** is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

**Existing Generating Capacity Resource** is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

**Existing Import Capacity Resource** is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

**Expedited Study Request** is defined in Section II.34.7 of the OATT.

**Export-Adjusted LSR** is as defined in Section III.12.4(b)(ii).

**Export Bid** is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

**Exports** are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

**External Elective Transmission Upgrade (External ETU)** is defined in Section I of Schedule 25 of the OATT.

**External Market Monitor** means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

**External Node** is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

**External Resource** means a generation resource located outside the metered boundaries of the New England Control Area.

**External Transaction** is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

**External Transmission Project** is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

**Facilities Study** is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

**Facility and Equipment Testing** means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

**Failure to Maintain Blackstart Capability** is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

**Failure to Perform During a System Restoration** is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

**Fast Start Demand Response Resource** is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

**Fast Start Generator** means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

**FCA Cleared Export Transaction** is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

**FCA Qualified Capacity** is the Qualified Capacity that is used in a Forward Capacity Auction.

**FCM Capacity Charge Requirements** are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

**FCM Charge Rate** is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

**FCM Commercial Operation** is defined in Section III.13.3.8 of Market Rule 1.

**FCM Deposit** is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

**FCM Financial Assurance Requirements** are described in Section VII of the ISO New England Financial Assurance Policy.

**Final Forward Reserve Obligation** is calculated in accordance with Section III.9.8(a) of Market Rule 1.

**Financial Assurance Default** results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

**Financial Assurance Obligations** relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

**Financial Transmission Right (FTR)** is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

**Firm Point-To-Point Service** is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

**Firm Transmission Service** is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

**Flexible DNE Dispatchable Generator** is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

**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.

**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 Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

**Forward Capacity Auction Starting Price** is calculated in accordance with Section III.13.2.4 of Market Rule 1.

**Forward Capacity Market (FCM)** is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

**Forward Reserve** means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.



**Forward Reserve Assigned Megawatts** is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

**Forward Reserve Auction** is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

**Forward Reserve Auction Offers** are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

**Forward Reserve Charge** is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

**Forward Reserve Clearing Price** is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

**Forward Reserve Credit** is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

**Forward Reserve Delivered Megawatts** are calculated in accordance with Section III.9.6.5 of Market Rule 1.

**Forward Reserve Delivery Period** is defined in Section III.9.1 of Market Rule 1.

**Forward Reserve Failure-to-Activate Megawatts** are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

**Forward Reserve Failure-to-Activate Penalty** is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

**Forward Reserve Failure-to-Activate Penalty Rate** is specified in Section III.9.7.2 of Market Rule 1.

**Forward Reserve Failure-to-Reserve**, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

**Forward Reserve Failure-to-Reserve Megawatts** are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

**Forward Reserve Failure-to-Reserve Penalty** is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

**Forward Reserve Failure-to-Reserve Penalty Rate** is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

**Forward Reserve Fuel Index** is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

**Forward Reserve Heat Rate** is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

**Forward Reserve Market** is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

**Forward Reserve MWs** are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

**Forward Reserve Obligation** is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

**Forward Reserve Obligation Charge** is defined in Section III.10.4 of Market Rule 1.

**Forward Reserve Offer Cap** is \$9,000/megawatt-month.

**Forward Reserve Payment Rate** is defined in Section III.9.8 of Market Rule 1.

**Forward Reserve Procurement Period** is defined in Section III.9.1 of Market Rule 1.

**Forward Reserve Qualifying Megawatts** refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

**Forward Reserve Resource** is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

**Forward Reserve Threshold Price** is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

**FTR Auction** is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

**FTR Auction Revenue** is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

**FTR 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 device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset 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 Charges** are defined in Section 1.3 of the ISO New England Billing Policy.

**Hourly PER** is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

**Hourly Requirements** are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

**Hourly Shortfall NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Hub** is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

**Hub Price** is calculated in accordance with Section III.2.8 of Market Rule 1.

**HQ Interconnection Capability Credit (HQICC)** is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

**Import Capacity Resource** means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

**Inadvertent Energy Revenue** is defined in Section III.3.2.1(o) of Market Rule 1.

**Inadvertent Energy Revenue Charges or Credits** is defined in Section III.3.2.1(p) 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 supply at the specified Location in the Day-Ahead Energy Market.

**Incremental ARR** is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

**Incremental ARR Holder** is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

**Incremental Cost of Reliability Service** is described in Section III.13.2.5.2.5.2 of Market Rule 1.

**Independent Transmission Company (ITC)** is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

**Information Request** is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

**Initial Market Participant Financial Assurance Requirement** is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

**Installed Capacity Requirement** means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

**Interchange Transactions** are transactions deemed to be effected under Market Rule 1.

**Interconnecting Transmission Owner** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Interconnection Agreement** is the “Large Generator Interconnection Agreement”, the “Small Generator Interconnection Agreement”, or the “Elective Transmission Upgrade Interconnection Agreement” pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

**Interconnection Customer** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.



**Interconnection Feasibility Study Agreement** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

**Interconnection Procedure** is the “Large Generator Interconnection Procedures”, the “Small Generator Interconnection Procedures”, or the “Elective Transmission Upgrade Interconnection Procedures” pursuant to Schedules 22, 23, and 25 of the ISO OATT.

**Interconnection Request** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

**Interconnection Rights Holder(s) (IRH)** has the meaning given to it in Schedule 20A to Section II of this Tariff.

**Interconnection System Impact Study Agreement** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

**Interest** is interest calculated in the manner specified in Section II.8.3.

**Interface Bid** is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

**Intermittent Power Resource** is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

**Internal Bilateral for Load** is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

**Internal Bilateral for Market for Energy** is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

**Internal Elective Transmission Upgrade (Internal ETU)** is defined in Section I of Schedule 25 of the OATT.

**Internal Market Monitor** means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

**Interregional Planning Stakeholder Advisory Committee (IPSAC)** is the committee described as such in the Northeast Planning Protocol.

**Interregional Transmission Project** is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

**Interruption Cost** is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

**Investment Grade Rating**, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

**Invoice** is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

**Invoice Date** is the day on which the ISO issues an Invoice.

**ISO** means ISO New England Inc.

**ISO Charges**, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

**ISO Control Center** is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

**ISO-Initiated Claimed Capability Audit** is the audit performed pursuant to Section III.1.5.1.4.

**ISO New England Administrative Procedures** means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

**ISO New England Billing Policy** is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

**ISO New England Filed Documents** means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

**ISO New England Financial Assurance Policy** is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

**ISO New England Information Policy** is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

**ISO New England Manuals** are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

**ISO New England Operating Documents** are the Tariff and the ISO New England Operating Procedures.

**ISO New England Operating Procedures (OPs)** are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

**ISO New England Planning Procedures** are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

**ISO New England System Rules** are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

**ITC Agreement** is defined in Attachment M to the OATT.

**ITC Rate Schedule** is defined in Section 3.1 of Attachment M to the OATT.

**ITC System** is defined in Section 2.2 of Attachment M to the OATT.

**ITC System Planning Procedures** is defined in Section 15.4 of Attachment M to the OATT.

**Joint ISO/RTO Planning Committee (JIPC)** is the committee described as such in the Northeastern Planning Protocol.

**Late Payment Account** is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

**Late Payment Account Limit** is defined in Section 4.2 of the ISO New England Billing Policy.

**Late Payment Charge** is defined in Section 4.1 of the ISO New England Billing Policy.

**Lead Market Participant**, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

**Limited Energy Resource** means a Generator Asset 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. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

**Load Management** means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage 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, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

**Load Shedding** is the systematic reduction of system demand by temporarily decreasing load.

**Load Zone** is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

**Local Area Facilities** are defined in the TOA.

**Local Benefit Upgrade(s) (LBU)** is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

**Local Control Centers** are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

**Local Delivery Service** is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

**Local Network** is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

**Local Network Load** is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

**Local Network RNS Rate** is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

**Local Network Service (LNS)** is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

**Local Point-To-Point Service (LPTP)** is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

**Local Public Policy Transmission Upgrade** is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

**Local Resource Adequacy Requirement** is calculated pursuant to Section III.12.2.1.1.

**Local Second Contingency Protection Resources** are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

**Local Service** is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

**Local Service Schedule** is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

**Local Sourcing Requirement (LSR)** is a value calculated as described in Section III.12.2.1 of Market Rule 1.

**Local System Planning (LSP)** is the process defined in Appendix 1 of Attachment K to the OATT.

**Localized Costs** are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade or a Public Policy Transmission Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

**Location** is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

**Locational Marginal Price (LMP)** is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or

Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

**Long Lead Time Facility (Long Lead Facility)** has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

**Long-Term** is a term of one year or more.

**Long-Term Transmission Outage** is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

**Loss Component** is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

**Loss of Load Expectation (LOLE)** is the probability of disconnecting non-interruptible customers due to a resource deficiency.

**Lost Opportunity Cost (LOC)** is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

**LSE** means load serving entity.

**Lump Sum Blackstart Payment** is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

**Lump Sum Blackstart Capital Payment** is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.



**Manual Response Rate** is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

**Marginal Loss Revenue Load Obligation** is defined in Section III.3.2.1(b) of Market Rule 1.

**Marginal Reliability Impact** is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

**Market Credit Limit** is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

**Market Credit Test Percentage** is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

**Market Efficiency Transmission Upgrade** is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

**Market Participant** is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

**Market Participant Financial Assurance Requirement** is defined in Section III of the ISO New England Financial Assurance Policy.

**Market Participant Obligations** is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

**Market Participant Service Agreement (MPSA)** is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

**Market Rule 1** is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

**Market Violation** is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

**Material Adverse Change** is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

**Material Adverse Impact** is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

**Maximum Capacity Limit** is a value calculated as described in Section III.12.2.2 of Market Rule 1.

**Maximum Consumption Limit** is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable,

must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

**Maximum Daily Consumption Limit** is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

**Maximum Facility Load** is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

**Maximum Interruptible Capacity** is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

**Maximum Load** is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

**Maximum Number of Daily Starts** is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

**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 an On-Peak Demand Resource or Seasonal Peak 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 On-Peak Demand Resources or Seasonal Peak 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 capability of the 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 capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the 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 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include 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 an On-Peak Demand Resource or Seasonal Peak Demand Resource 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 On-Peak Demand Resources or Seasonal Peak Demand Resources 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 capability of the On-Peak Demand Resource or Seasonal Peak 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 an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak 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), 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.

**Metered Quantity For Settlement** is defined in Section III.3.2.1.1 of Market Rule 1.

**Minimum Consumption Limit** is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's

Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

**Minimum Down Time** is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

**Minimum Generation Emergency** means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

**Minimum Generation Emergency Credits** are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

**Minimum Reduction** is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

**Minimum Reduction Time** is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

**Minimum Run Time** is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

**Minimum Time Between Reductions** is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

**Minimum Total Reserve Requirement**, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**Monthly Blackstart Service Charge** is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

**Monthly Capacity Payment** is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

**Monthly Peak** is defined in Section II.21.2 of the OATT.

**Monthly PER** is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

**Monthly Real-Time Demand Reduction Obligation** is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWs.

**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.

**MRI Transition Period** is the period specified in Section III.13.2.2.1.

**MUI** is the market user interface.

**Municipal Market Participant** is defined in Section II of the ISO New England Financial Assurance Policy.

**MW** is megawatt.

**MWh** is megawatt-hour.

**Native Load Customers** are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

**NCPC Charge** means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

**NCPC Credit** means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

**Needs Assessment** is defined in Section 4.1 of Attachment K to the OATT.

**NEMA**, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

**NEMA Contract** is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

**NEMA Load Serving Entity (NEMA LSE)** is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

**NEMA or Northeast Massachusetts Upgrade**, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited



to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

**NEPOOL** is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

**NEPOOL Agreement** is the agreement among the participants in NEPOOL.

**NEPOOL GIS** is the generation information system.

**NEPOOL GIS Administrator** is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

**NEPOOL GIS API Fees** are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

**NEPOOL Participant** is a party to the NEPOOL Agreement.

**NERC** is the North American Electric Reliability Corporation or its successor organization.

**NESCOE** is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

**Net Commitment Period Compensation (NCPC)** is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

**Net CONE** is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

**Net Regional Clearing Price** is described in Section III.13.7.5 of Market Rule 1.

**Net Supply** is energy injected into the transmission or distribution system at a Retail Delivery Point.

**Net Supply Capability** is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

**Network Capability Interconnection Standard** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Network Customer** is a Transmission Customer receiving RNS or LNS.

**Network Import Capability (NI Capability)** is defined in Section I of Schedule 25 of the OATT.

**Network Import Interconnection Service (NI Interconnection Service)** is defined in Section I of Schedule 25 of the OATT.

**Network Resource** is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

**New Brunswick Security Energy** is defined in Section III.3.2.6A of Market Rule 1.

**New Capacity Offer** is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

**New Capacity Qualification Deadline** is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

**New Capacity Qualification Package** is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

**New Capacity Resource** is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

**New Capacity Show of Interest Form** is described in Section III.13.1.1.2.1 of Market Rule 1.

**New Capacity Show of Interest Submission Window** is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

**New Demand Capacity Resource** is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

**New Demand Capacity Resource Qualification Package** is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

**New Demand Capacity Resource Show of Interest Form** is described in Section III.13.1.4.1.1.1 of Market Rule 1.

**New England Control Area** is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

**New England Markets** are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

**New England System Restoration Plan** is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

**New England Transmission System** is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

**New Generating Capacity Resource** is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

**New Import Capacity Resource** is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

**New Resource Offer Floor Price** is defined in Section III.A.21.2.

**NMPTC** means Non-Market Participant Transmission Customer.

**NMPTC Credit Threshold** is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

**NMPTC Financial Assurance Requirement** is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

**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 Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset 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 Generator Asset 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.13.7.5.1.3.

**Non-Commercial Capacity** is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

**Non-Commercial Capacity Cure Period** is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

**Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount)** is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

**Non-Designated Blackstart Resource Study Cost Payments** are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

**Non-Dispatchable Resource** is any Resource that does not meet the requirements to be a Dispatchable Resource.

**Non-Hourly Charges** are defined in Section 1.3 of the ISO New England Billing Policy.

**Non-Hourly Requirements** are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

**Non-Incumbent Transmission Developer** is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. “Non-Incumbent Transmission Developer” also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

**Non-Incumbent Transmission Developer Operating Agreement (or NTDOA)** is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

**Non-Market Participant** is any entity that is not a Market Participant.

**Non-Market Participant Transmission Customer** is any entity which is not a Market Participant but is a Transmission Customer.

**Non-Municipal Market Participant** is defined in Section II of the ISO New England Financial Assurance Policy.

**Non-PTF Transmission Facilities (Non-PTF)** are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

**Non-Qualifying** means a Market Participant that is not a Credit Qualifying Market Participant.

**Notice of RBA** is defined in Section 6.3.2 of the ISO New England Billing Policy.

**Notification Time** is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

**Northeastern Planning Protocol** is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: [www.iso-ne.com/static-assets/documents/2015/07/northeastern\\_protocol\\_dmeast.doc](http://www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc).

**NPCC** is the Northeast Power Coordinating Council.

**Obligation Month** means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

**Offer Data** means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of 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 or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

**Offered CLAIM30** is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

**On-Peak Demand Resource** is a type of Demand Capacity 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 Generator Asset or a Load Asset, where such facility 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.

**Passive DR Audit** is the audit performed pursuant to Section III.13.6.1.5.4.

**Passive DR Auditing Period** is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

**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.13.7.1.2 of Market Rule 1.

**PER Proxy Unit** is described in Section III.13.7.1.2.1 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 Capacity Resource in the Forward Capacity

Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

**Phase I Transfer Credit** is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

**Phase I/II HVDC-TF** is defined in Schedule 20A to Section II of this Tariff.

**Phase I/II HVDC-TF Transfer Capability** is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The “Phase I Transfer Capability” is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability.

Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

**Phase One Proposal** is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

**Phase II Transfer Credit** is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

**Phase Two Solution** is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

**Planning Advisory Committee** is the committee described in Attachment K of the OATT.

**Planning and Reliability Criteria** is defined in Section 3.3 of Attachment K to the OATT.

**Planning Authority** is an entity defined as such by the North American Electric Reliability Corporation.

**Point(s) of Delivery (POD)** is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

**Point of Interconnection** shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of 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.

**Posting Entity** is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

**Posture** means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

**Posturing Credits** are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

**Power Purchaser** is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

**Principal** is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

**Profiled Load Assets** include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

**Project Sponsor** is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

**Proxy De-List Bid** is a type of bid used in the Forward Capacity Market.

**Provisional Member** is defined in Section I.68A of the Restated NEPOOL Agreement.

**PTO Administrative Committee** is the committee referred to in Section 11.04 of the TOA.

**Public Policy Requirement** is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

**Public Policy Transmission Study** is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

**Public Policy Local Transmission Study** is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

**Public Policy Transmission Upgrade** is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

**Publicly Owned Entity** is defined in Section I of the Restated NEPOOL Agreement.

**Qualification Process Cost Reimbursement Deposit** is described in Section III.13.1.9.3 of Market Rule 1.

**Qualified Capacity** is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

**Qualified Generator Reactive Resource(s)** is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

**Qualified Non-Generator Reactive Resource(s)** is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

**Qualified Reactive Resource(s)** is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

**Qualified Transmission Project Sponsor** is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

**Queue Position** has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

**Rapid Response Pricing Asset** is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

**Rapid Response Pricing Opportunity Cost** is the NCPC Credit described in Section III.F.2.3.10.

**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.

**Rationing Minimum Limit** is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which an offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

**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) of Market Rule 1.

**Real-Time Adjusted Load Obligation Deviation** is defined in Section III.3.2.1(d) of Market Rule 1.

**Real-Time Commitment NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Congestion Revenue** is defined in Section III.3.2.1(i) of Market Rule 1.

**Real-Time Demand Reduction Obligation** is defined in Section III.3.2.1(c) of Market Rule 1.

**Real-Time Demand Reduction Obligation Deviation** is defined in Section III.3.2.1(e) of Market Rule 1.

**Real-Time Dispatch NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Energy Market** means the purchase or sale of energy, purchase of demand reductions, 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(g) of Market Rule 1.

**Real-Time Energy Market Deviation Energy Charge/Credit** is defined in Section III.3.2.1(g) of Market Rule 1.

**Real-Time Energy Market Deviation Loss Charge/Credit** is defined in Section III.3.2.1(g) of Market Rule 1.

**Real-Time Energy Market NCPC Credits** are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

**Real-Time External Transaction NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Generation Obligation** is defined in Section III.3.2.1(b) of Market Rule 1.

**Real-Time Generation Obligation Deviation** is defined in Section III.3.2.1(d) of Market Rule 1.

**Real-Time High Operating Limit** is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).



**Real-Time Load Obligation** is defined in Section III.3.2.1(b) of Market Rule 1.

**Real-Time Load Obligation Deviation** is defined in Section III.3.2.1(d) of Market Rule 1.

**Real-Time Locational Adjusted Net Interchange** is defined in Section III.3.2.1(b) of Market Rule 1.

**Real-Time Locational Adjusted Net Interchange Deviation** is defined in Section III.3.2.1(d) of Market Rule 1.

**Real-Time Loss Revenue** is defined in Section III.3.2.1(l) 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 Offer Change** is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

**Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time Prices** means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

**Real-Time Reserve Charge** is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

**Real-Time Reserve Clearing Price** is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

**Real-Time Reserve Credit** is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement 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 described in Section III.1.7.19 of Market Rule 1.

**Real-Time Reserve Opportunity Cost** is defined in Section III.2.7A(b) of Market Rule 1.

**Real-Time Synchronous Condensing NCPC Credit** is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

**Real-Time System Adjusted Net Interchange** means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

**Receiving Party** is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

**Reference Level** is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

**Regional Benefit Upgrade(s) (RBU)** means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

**Regional Network Load** is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any

behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

**Regional Network Service (RNS)** is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

**Regional Planning Dispute Resolution Process** is described in Section 12 of Attachment K to the OATT.

**Regional System Plan (RSP)** is the plan developed under the process specified in Attachment K of the OATT.

**Regional Transmission Service (RTS)** is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

**Regulation** is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

**Regulation and Frequency Response Service** is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

**Regulation Capacity** is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

**Regulation Capacity Requirement** is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

**Regulation Capacity Offer** is an offer by a Market Participant to provide Regulation Capacity.

**Regulation High Limit** is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

**Regulation Low Limit** is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

**Regulation Market** is the market described in Section III.14 of Market Rule 1.

**Regulation Resources** are those Alternative Technology Regulation Resources, Generator Assets, and Dispatchable Asset Related Demands that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

**Regulation Service** is the change in output or consumption made in response to changing AGC SetPoints.

**Regulation Service Requirement** is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

**Regulation Service Offer** is an offer by a Market Participant to provide Regulation Service.

**Related Person** is defined pursuant to Section 1.1 of the Participants Agreement.

**Related Transaction** is defined in Section III.1.4.3 of Market Rule 1.

**Reliability Administration Service (RAS)** is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

**Reliability Committee** is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

**Reliability Markets** are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

**Reliability Region** means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

**Reliability Transmission Upgrade** means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

**Remittance Advice** is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

**Remittance Advice Date** is the day on which the ISO issues a Remittance Advice.

**Renewable Technology Resource** is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

**Re-Offer Period** is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with

Dispatchable Asset Related Demands or, 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 Quantity For Settlement** is defined in Section III.10.1 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 Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or 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.

**Retirement De-List Bid** is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

**Returning Market Participant** is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

**Revenue Requirement** is defined in Section IV.A.2.1 of the Tariff.

**Reviewable Action** is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

**Reviewable Determination** is defined in Section 12.4(a) of Attachment K to the OATT.

**RSP Project List** is defined in Section 1 of Attachment K to the OATT.

**RTEP02 Upgrade(s)** means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

**RTO** is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission’s corresponding regulation.

**Same Reserve Zone Export Transaction** is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

**Sanctionable Behavior** is defined in Section III.B.3 of Appendix B of Market Rule 1.

**Schedule, Schedules, Schedule 1, 2, 3, 4 and 5** are references to the individual or collective schedules to Section IV.A. of the Tariff.

**Schedule 20A Service Provider (SSP)** is defined in Schedule 20A to Section II of this Tariff.

**Scheduling Service**, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

**Scheduling, System Control and Dispatch Service**, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

**Seasonal Claimed Capability** is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

**Seasonal Claimed Capability Audit** is the Generator Asset audit performed pursuant to Section III.1.5.1.3.



**Seasonal DR Audit** is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

**Seasonal Peak Demand Resource** is a type of Demand Capacity 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 its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing 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 committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

**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.C 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.

**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).

**Sponsored Policy Resource** is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.

**Stage One Proposal** is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

**Stage Two Solution** is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

**Standard Blackstart Capital Payment** is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

**Start-of-Round Price** is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

**Start-Up Fee** is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset 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 Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

**Station** is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

**Station Going Forward Common Costs** are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

**Station-level Blackstart O&M Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Station-level Specified-Term Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Station-level Standard Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Storage DARD** is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

**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 pursuant to Section III.9. 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.

**Supply Offer** is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

**Supply Offer Block-Hours** are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

**Synchronous Condenser** is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

**System Condition** is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

**System Impact Study** is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a

request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

**System Operator** shall mean ISO New England Inc. or a successor organization.

**System-Wide Capacity Demand Curve** is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

**TADO** is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

**Tangible Net Worth** is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock; (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

**Technical Committee** is defined in Section 8.2 of the Participants Agreement.

**Ten-Minute Non-Spinning Reserve (TMNSR)** is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

**Ten-Minute Non-Spinning Reserve Service** is the form of Ancillary Service described in Schedule 6 of the OATT.

**Ten-Minute Reserve Requirement** is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**Ten-Minute Spinning Reserve (TMSR)** is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

**Ten-Minute Spinning Reserve Requirement** is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**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)** is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

**Thirty-Minute Operating Reserve Service** is the form of Ancillary Service described in Schedule 7 of the OATT.

**Through or Out Rate (TOUT Rate)** is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

**Through or Out Service (TOUT Service)** means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over

the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

**Tie-Line Asset** is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

**Total Available Amount** is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

**Total Blackstart Capital Payment** is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

**Total Blackstart 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 Reserve Requirement**, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

**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 Constraint Penalty Factors** are described in Section III.1.7.5 of Market Rule 1.

**Transmission Credit Limit** is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

**Transmission Credit Test Percentage** is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

**Transmission Customer** is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

**Transmission Default Amount** is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

**Transmission Default Period** is defined in Section 3.4.f of the ISO New England Billing Policy.

**Transmission Late Payment Account** is defined in Section 4.2 of the ISO New England Billing Policy.

**Transmission Late Payment Account Limit** is defined in Section 4.2 of the ISO New England Billing Policy.

**Transmission Late Payment Charge** is defined in Section 4.1 of the ISO New England Billing Policy.

**Transmission, Markets and Services Tariff (Tariff)** is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

**Transmission Obligations** are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

**Transmission Operating Agreement (TOA)** is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

**Transmission Owner** means a PTO, MTO or OTO.

**Transmission Provider** is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

**Transmission Requirements** are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

**Transmission Security Analysis Requirement** shall be determined pursuant to Section III.12.2.1.2.

**Transmission Service Agreement (TSA)** is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

**Transmission Upgrade(s)** means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

**UDS** is unit dispatch system software.

**Unconstrained Export Transaction** is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

**Uncovered Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Uncovered Transmission Default Amounts** are defined in Section 3.4.f of the ISO New England Billing Policy.

**Unrated** means a Market Participant that is not a Rated Market Participant.

**Unsecured Covered Entity** is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

**Unsecured Municipal Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Unsecured Municipal Market Participant** is defined in Section 3.3(h) of the ISO New England Billing Policy.

**Unsecured Municipal Transmission Default Amount** is defined in Section 3.4.f of the ISO New England Billing Policy.

**Unsecured Non-Municipal Covered Entity** is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than \$0 under the ISO New England Financial Assurance Policy.

**Unsecured Non-Municipal Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Unsecured Non-Municipal Transmission Default Amount** is defined in Section 3.3(i) of the ISO New England Billing Policy.

**Unsecured Transmission Default Amounts** are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

**Unsettled FTR Financial Assurance** is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

**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 On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated 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 pursuant to Section III.9. 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.

**Zonal Capacity Obligation** is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

**Zonal Reserve Requirement** is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

## 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, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance 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, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance 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) The following 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) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.
- (iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR 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) An Establish Claimed Capability Audit may be performed only by a Generator Asset.
- (b) The time and date of an Establish Claimed Capability Audit shall be unannounced.
- (c) For a newly commercial Generator Asset:
  - (i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:
    1. Non-intermittent daily cycle hydro;
    2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
    3. Intermittent Generator Assets
  - (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.
- (d) 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 five 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 one Business Day 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.
- (e) 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.
  - (f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.
  - (g) To conduct an Establish Claimed Capability Audit, the ISO shall:
    - (i) Initiate an Establish 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.
    - (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
    - (iii) 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.
  - (h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

<b>Duration Required for an Establish Claimed Capability Audit</b>	
<b>Type</b>	<b>Claimed Capability Audit Duration (Hrs)</b>
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4

Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

- (i) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.2(h).

**III.1.5.1.3. Seasonal Claimed Capability Audits.**

- (a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.
- (b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:
- (i) Non-intermittent daily hydro; and
  - (ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).
- (c) 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.
- (d) Except as provided in Section III.1.5.1.3(n) 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.
- (e) 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.
- (f) 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 fifth 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.
- (g) 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.
- (h) 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(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.
- (i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

<b>Duration Required for a Seasonal Claimed Capability Audit</b>	
<b>Type</b>	<b>Claimed Capability Audit Duration (Hrs)</b>
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2

Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible (Electric Storage)	2
Hydraulic Turbine-Other	
Hydro-Conventional Weekly	2
Fuel Cell	1
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

- (k) 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.
- (l) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, 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.
- (m) 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.

- (n) 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(f).
  - (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(d)(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(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.
- (o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.3(j).

#### **III.1.5.1.3.1 Seasonal DR Audits.**

- (a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

- (b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.
- (c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:
  - (i) At least once every Capability Demonstration Year;
  - (ii) During the months of April through November;
- (d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:
  - (i) At least once every Capability Demonstration Year;
  - (ii) During the months of December through March.
- (e) A Seasonal DR Audit may be performed either:
  - (i) At the request of a Market Participant as described in subsection (f) below; or
  - (ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.
- (f) If a Market Participant requests a Seasonal DR Audit:
  - (i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.
  - (ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.
  - (iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.
  - (iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
  - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:
  - (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth 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 DR Audit.
  - (iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.
  - (iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

- (h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.
- (i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.
- (j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.
- (k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.
- (l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.
- (m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.
- (n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.
- (o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

**III.1.5.1.4. ISO-Initiated Claimed Capability 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 either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both 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 for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.
- (ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset 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 for a Generator Asset 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) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day 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) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.
  - (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
  - (iii) For Generator Assets, 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.
  - (iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
- (f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

<b>Duration Required for an ISO-Initiated Claimed Capability Audit</b>	
<b>Type</b>	<b>Claimed Capability Audit Duration (Hrs)</b>
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4

Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage)	2
Hydraulic Turbine – Other	
Hydro-Conventional Daily Pondage	2
Hydro-Conventional Run of River	
Hydro-Conventional Weekly	
Wind	2
Photovoltaic	
Fuel Cell	
Other Electric Storage (Excludes Hydraulic Turbine – Reversible)	2
Demand Response Resource	1

- (g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource type not listed in Section III.1.5.1.4(f).

### III.1.5.2 ISO-Initiated Parameter Auditing.

- (a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide real-time energy or reserves.
- (b) Generator audits shall be performed using the following methods for the relevant parameter:
- (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 in accordance with Section III.9.5.
  - (vi) **CLAIM30.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
  - (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 electronic Dispatch Instructions.
  - (viii) **Dual Fuel Capability.** A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).
- (c) Demand Response Resource audits shall be performed using the following methods:
- (i) **Maximum Reduction.** The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.
  - (ii) **Demand Response Resource Ramp Rate.** The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.
  - (iii) **Demand Response Resource Start-Up Time.** The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.
  - (iv) **Demand Response Resource Notification Time.** The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.
  - (v) **CLAIM10.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.
  - (vi) **CLAIM30.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
- (d) To conduct an audit based upon historical data, the ISO shall:
- (i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or
  - (ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.

- (e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.
- (f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:
  - (i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.
  - (ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.
- (g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.
- (h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:
  - (i) The 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 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 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 parameter value restriction;
    2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
    3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

### **III.1.5.3 Reactive Capability Audits.**

- (a) Two types of Reactive Capability Audits may be performed:
  - (i) A Lagging Reactive Capability Audit measures the Generator Asset's ability to provide reactive power to the transmission system at a specified real power output.
  - (ii) A Leading Reactive Capability Audit measures the Generator Asset's ability to absorb reactive power from the transmission system at a specified real power output.
- (b) The ISO shall develop a list of Generator Assets that must conduct Reactive Capability Audits.
- (c) Unless otherwise directed by the ISO, Generator Assets that are required to perform Reactive Capability Audits must perform both a Lagging Reactive Capability Audit and a Leading Reactive Capability Audit.
- (d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.
- (e) The Reactive 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.
- (f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.
- (g) Reactive Capability Audits must be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Generator Asset to conduct Reactive Capability Audits more often than every five years if:
  - (i) there is a change in the Generator Asset that may affect the reactive power capability of the Generator Asset;
  - (ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Generator Asset; or
  - (iii) historical data shows that the amount of reactive power that the Generator Asset can provide to or absorb from the transmission system is higher or lower than the latest audit data.
- (h) The Lead Market Participant may request a waiver of the requirement to conduct a Reactive Capability Audit. The ISO, at its sole discretion, will determine whether and for how long a waiver can be granted.

**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**                    **Transmission Constraint Penalty Factors.**

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is \$10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is \$30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any

transmission constraint is \$30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

### **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, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the 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 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 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 limitations and 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 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.**

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.



### **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 review of historical data for non-intermittent daily cycle hydro.
  - (ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.
  - (iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:
    - a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.
    - b. For a Generator Asset that is off-line and not available for commitment shall be zero.
    - c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.
  - (iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

### **III.1.7.12 Seasonal DR Audit Value of an Active Demand Capacity Resource.**

- (a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through

November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.

- (b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

**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 endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. 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 Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

**III.1.7.18** **Ramping.**

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to sanctions for failure to comply as described in **Appendix B**.

**III.1.7.19** **Real-Time Reserve Designation.**

The ISO shall determine the Real-Time Reserve Designation for each eligible Resource in accordance with this Section III.1.7.19. The Real-Time Reserve Designation shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve.

**III.1.7.19.1** **Eligibility.**

To be eligible to receive a Real-Time Reserve Designation, a Resource must meet all of the criteria enumerated in this Section III.1.7.19.1. A Resource that does not meet all of these criteria is not eligible to provide Operating Reserve and will not receive a Real-Time Reserve Designation.

- (1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.
- (2) The Resource must not be part of the first contingency supply loss.
- (3) The Resource must not be designated as constrained by transmission limitations.
- (4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)
- (5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

### **III.1.7.19.2 Calculation of Real-Time Reserve Designation.**

#### **III.1.7.19.2.1 Generator Assets.**

##### **III.1.7.19.2.1.1 On-line Generator Assets.**

The Manual Response Rate used in calculations in this section shall be the lesser of the Generator Asset's offered Manual Response Rate and its audited Manual Response Rate as described in Section III.1.5.2.

- (a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.

- (b) **Ten-Minute Non-Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Non-Spinning Reserve shall be zero. For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit).
  
- (c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

#### **III.1.7.19.2.1.2 Off-line Generator Assets.**

For an off-line Generator Asset that is not a Fast Start Generator, all components of the Real-Time Reserve Designation shall be zero.

- (a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.
  
- (b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).

- (c) **Thirty-Minute Operating Reserve.** For an off-line Fast Start Generator, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Fast Start Generator's Offered CLAIM30, its CLAIM30, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Thirty-Minute Operating Reserve shall be zero, except during the last thirty minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Thirty-Minute Operating Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires), minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Fast Start Generator pursuant to subsection (b) above.

### **III.1.7.19.2.2 Dispatchable Asset Related Demand.**

#### **III.1.7.19.2.2.1 Storage DARDs.**

- (a) **Ten-Minute Spinning Reserve.** For a Storage DARD, Ten-Minute Spinning Reserve shall be calculated as the absolute value of the amount of current telemetered consumption.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.
- (c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

#### **III.1.7.19.2.2.2 Dispatchable Asset Related Demand Other Than Storage DARDs.**

- (a) **Ten-Minute Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit). For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

- (b) **Ten-Minute Non-Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit).
- (c) **Thirty-Minute Operating Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (a) above. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Non-Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (b) above.

### **III.1.7.19.2.3 Demand Response Resources.**

For a Demand Response Resource that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2.

#### **III.1.7.19.2.3.1 Dispatched.**

- (a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be

calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction). For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

- (b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction).
- (c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within thirty minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction) minus the Ten-Minute Spinning Reserve quantity calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

#### **III.1.7.19.2.3.2 Non-Dispatched.**

For a Demand Response Resource that is not being dispatched that is not a Fast Start Demand Response Resource, all components of the Real-Time Reserve Designation shall be zero.

- (a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Demand Response Resource's Offered CLAIM10, its CLAIM10, and its Maximum Reduction.

- (c) **Thirty-Minute Operating Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Fast Start Demand Response Resource's Offered CLAIM30, its CLAIM30, and its Maximum Reduction, minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Demand Response Resource pursuant to subsection (b) above.

### **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 Resources 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, consumption, or demand reduction levels of Generator Assets, DARDs, or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and 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.



(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands 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 or demand reduction capability 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 Generator Asset 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 Generator Assets or Demand Response 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 or Demand Reduction Offers.

### **III.1.10.1A Energy Market Scheduling.**

The submission of Day-Ahead offers and bids 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) **Locational Demand Bids** – 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 Resources 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) **External Transactions** – All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets 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 submitted under Section III.1.10.7 and 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.
- (c) **Generator Asset Supply Offers** – Market Participants selling into the New England Markets from Generator Assets or External Resources may submit Supply Offers or External Transactions for the supply of energy for the following Operating Day. (Coordinated External Transactions shall be submitted to the ISO in accordance with Section III.1.10.7.A of this Market Rule 1.)

Such Supply Offers:

- (i) Shall specify the Resource and 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 prices and quantities in a Block may each vary on an hourly basis;
- (ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type 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 Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including 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 available energy, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;

(vi) Shall not specify an energy offer below the Energy Offer Floor or above the Energy Offer Cap; and

(vii) Shall, in the case of a Supply Offer from a Continuous Storage Generator Asset, also meet the requirements specified in Section III.1.10.6.

**(d) DARD Demand Bids** – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including 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;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit;

(iv) Shall not specify a bid price below the Energy Offer Floor or above the Energy Offer Cap;

(v) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers** – Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is above the Energy Offer Cap, below the Energy Offer Floor, or below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

- (iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.
  - (iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.
  - (v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.
  - (vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.
  - (vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.
- (f) **Demand Reduction Threshold Price** – The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:
- (a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.
  - (b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.
  - (c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.
  - (d) A historic threshold price  $P_{th}$  shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of

Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.

- (e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$D RTP = P_{th} X \frac{FPI_c}{FPI_h}$$

where  $FPI_h$  is the historic fuel price index for the same month of the previous year, and  $FPI_c$  is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15<sup>th</sup> day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction 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, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) **Load Estimate** – 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) **Prorated Supply** – In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction 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, Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction 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, Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) **Prorated Demand** – 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) **Virtuals** – 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, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources 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 supply or consumption and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(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 and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

(c) Market Participants offering energy from 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) 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.

#### **III.1.10.3 Self-Scheduled Resources.**

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD 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. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource shall not be Self-Scheduled.

#### **III.1.10.4 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 and Section III.1.10.7.A 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.1.10.5 Dispatchable Asset Related Demand.**

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

- (i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;
- (ii) 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;
- (iii) abide by the ISO maintenance coordination procedures; and
- (iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

#### **III.1.10.6 Electric Storage**

A storage facility is a facility that is capable of receiving electricity from the grid and storing the energy for later injection of electricity back to the grid. A storage facility may participate in the New England Markets as described below.

- (a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:
- (i) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;
  - (ii) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;
  - (iii) settle its injection of electricity to the grid as a Generator Asset and its receipt of electricity from the grid as a DARD; and
  - (iv) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.
- (b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:
- (i) satisfy the requirements applicable to an Electric Storage Facility;
  - (ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and
  - (iii) comprise one or more reversible hydraulic turbines.
- (c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:
- (i) satisfy the requirements applicable to an Electric Storage Facility;
  - (ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;
  - (iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;
  - (iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;
  - (v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time,

Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;

- (vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;
  - (vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and
  - (viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).
- (d) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.
- (e) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.
- (f) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)
- (g) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.
- (h) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

### **III.1.10.7 External Transactions.**

The provisions of this Section III.1.10.7 do not apply to Coordinated 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) [Reserved.]

(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) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) 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.1.10.7.A Coordinated External Transactions.**

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated NERC E-Tag at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would

create or worsen an Emergency, unless applicable procedures governing the Emergency permit the transaction to be scheduled.

### **III.1.10.7.B                    Coordinated Transactions Scheduling Threshold Trigger to Tie Optimization**

#### **(a)        Background and Overview**

This Section III.1.10.B describes the process for filing amendments to the Transmission, Markets and Services Tariff under Section 205 of the Federal Power Act in the event that the production cost savings of the ISO's interchange on the New York – New England AC Interface, including the Northport/Norwalk Line, following the implementation of an inter-regional interchange scheduling process known as Coordinated Transaction Scheduling, are not satisfactory. The determination of whether savings are satisfactory will be based on actions, thresholds and triggers described in this Section III.1.10.7.B. If pursuant to the actions, thresholds and triggers described in this Section III.1.10.7.B, the production costs savings of Coordinated Transaction Scheduling are not satisfactory, and a superior alternative has not become known, the ISO will file tariff amendments with the Commission to implement the inter-regional interchange scheduling process described to the ISO stakeholders in 2011 as Tie Optimization.

If, pursuant to the timetables presented, the ISO determines the thresholds described herein have not triggered, the process for filing amendments to the ISO tariff as described herein ceases, the provisions of this Section III.1.10.7.B become null and void and the ISO will continue to implement Coordinated Transaction Scheduling unless and until future Section 205 filings are pursued to amend Coordinated Transaction Scheduling.

#### **(b)        The Two-Year Analysis**

Within 120 days of the close of the first and second years following the date that Coordinated Transaction Scheduling as an interface scheduling tool is activated in the New England and New York wholesale electricity markets, the External Market Monitor will develop, for presentation to and comment by, New England stakeholders, an analysis, of:

(i)        the Tie Optimization interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the ISO and New York Independent System

Operator received an infinite number of zero bids in the Coordinated Transaction Scheduling process, which utilizes the supply curves and forecasted prices for each market; and

(ii) an optimal interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the two ISOs had an infinite number of zero bids in the Coordinated Transaction Scheduling process, but utilizing actual real-time prices from each market rather than the forecasted prices that were used in the Coordinated Transaction Scheduling process.

The bid production cost savings associated with the Tie Optimization interchange as developed in (i) above for the second year following the date that Coordinated Transaction Scheduling is activated in the New England and New York wholesale electricity markets will reveal the “foregone” production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(b)(1) formula as the term “b.” The difference in bid production cost savings between (i) and (ii) above will reveal the “foregone” bid production cost savings of the Tie Optimization interchange as developed in (i) above rather than an optimal interchange as developed in (ii) above, represented in the Section III.1.10.7.B(b)(1) formula as the term “a.”

This analysis will be consistent with presentations made by the External Market Monitor to the New England stakeholders during 2011 on the issue of the benefits of Coordinated Transaction Scheduling.

(1) Using the above calculations, the External Market Monitor will compute the following ratio:

$b/a$

If, the ratio  $b/a$  is greater than 60% and  $b$  is greater than \$3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(c) Improving Coordinated Transaction Scheduling

(1) If the ratio, developed pursuant to Section III.1.10.7.B(b)(1), is greater than 60% and  $b$  is greater than \$3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(2) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(3) If the ISO declares that the threshold has triggered, the External Market Monitor will provide recommendations of adjustments to the design or operation of Coordinated Transaction Scheduling to improve the production cost savings available from its implementation.

(4) The ISO, considering the input of the New England stakeholders and the recommendation of the External Market Monitor, will develop and implement adjustments to Coordinated Transaction Scheduling. To the extent tariff revisions are necessary to implement the adjustments to Coordinated Transaction Scheduling, the ISO will file such revisions with the Commission as a compliance filing in the Coordinated Transaction Scheduling docket. If no adjustments to Coordinated Transaction Scheduling have been identified, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing.

(d) The Second Analysis

(1) Within 120 days of the close of the twelve months following the date that the adjustments to Coordinated Transaction Scheduling, developed under Section III.1.10.7.B(c), are activated in the New England and New York wholesale electricity markets, the External Market Monitor will present a second analysis to New England stakeholders. The analysis will be consistent with the analysis described in Section III.1.10.7.B(b) but will develop bid production cost savings for the twelve month period during which the adjustments developed in Section III.1.10.7.B(c) are in place.

(2) The bid production cost savings associated with the Tie Optimization interchange as developed in Section III.1.10.7.B(d)(1) will reveal the “foregone” bid production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(d)(3) formula as the term “b.” The different in bid production cost savings between the Tie Optimization interchange and the optimal interchange, as developed in Section III.1.10.7.B(d)(1), will reveal the “foregone” bid production cost savings of the Tie Optimization interchange rather than the optimal interchange, represented in the Section III.1.10.7.B(d)(3) formula as the term “a.”

(3) Using the above calculations, the External Market Monitor will compute the following ratio:

b/a

If the ratio  $b/a$  is greater than 60% and  $b$  is greater than \$3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(4) If the ratio  $b/a$  is greater than 60% and  $b$  is greater than \$3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(5) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(6) If the ISO declares the threshold has triggered, considering the input of the stakeholders and the recommendation of the External Market Monitor, the ISO will determine whether a superior alternative has been proposed. If the ISO and the New York Independent System Operator both determine a superior alternative has been proposed, the ISO will prepare tariff amendments to be filed with the Commission to implement the superior alternative, and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments and will not pursue the balance of the actions required by this Section III.1.10.7.B.

(7) If the ISO determines a superior alternative has not been proposed, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing. Tie Optimization was described for stakeholders in the *Design Basis Document* for NE/NY Inter-Regional Interchange Scheduling presented at a NEPOOL Participants Committee meeting on June 10, 2011.

(e) The Compliance Filing

The ISO will develop tariff language to implement the inter-regional interchange scheduling practice known as Tie Optimization through a compliance filing with the Commission and will present those

amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments.

#### **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 Resources and to direct that schedules be changed to address an actual or potential 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 Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. 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) 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 ISO New England Manual M-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. The External Transaction re-offer provisions of this Section III.1.10.9(c) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) 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 Generator Assets), and the quantity and price pairs of its Blocks may be modified.
  - (ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.
- (d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.
- (e) 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. A Market Participant may not request to Self-Schedule a Demand Response Resource. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.
- (f) 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(c), 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 at a specified value. 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 at or above the requested amount for the hour in question.

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

(i) 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 or Consumption and Demand Reduction.**

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) 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; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) 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 Dispatchable Resources.**

With the exception of Settlement Only Resources, Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, nuclear-powered Resources and photovoltaic Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

- (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 Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable 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 for a Dispatchable Resource 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.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind and hydro Intermittent Power Resources that are not Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

(i) A wind or hydro Intermittent Power Resource not capable of receiving and responding to electronic Dispatch Instructions will be manually dispatched.

(ii) A Market Participant may elect, but is not required, to have a wind or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.

(iii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.

(f) The ISO may request that dual-fuel Generator Assets 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-fuel Generator Assets 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-fuel Generator Assets 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 Dispatchability Requirements for Intermittent Power Resources.**

- (a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.
- (b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

#### **III.1.11.6 Non-Dispatchable Resources.**

Non-Dispatchable Resources are subject to the following requirements:

(a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource 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.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

### **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, DRR Aggregation 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 electric 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 resources 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 Offer Data, 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. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices shall be determined every five minutes and 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. 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 zonal 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 power flow solution produced by the State Estimator for the pricing interval, 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 Adjustment for Rapid Response Pricing Assets.**

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO, is in a dispatchable mode, and is not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee, No-Load Fee, or Interruption Cost is specified in the submitted Offer Data, a value of zero shall be used; if no Minimum Run Time or Minimum Reduction Time is specified in the submitted Offer Data, or if the submitted Minimum Run Time or Minimum Reduction Time is less than 15 minutes, a duration of 15 minutes shall be used; and the energy offer after adjustment shall not exceed the Energy Offer Cap.

(a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Binary Storage DARD, its Minimum Consumption Limit shall be set to zero; if the Rapid Response Pricing Asset is a Fast Start Demand Response Resource, its Minimum Reduction shall be set to zero.

(b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.

(c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.

(d) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.

(e) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.

### **III.2.5 Calculation of Nodal Real-Time 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 power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), 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 Generator Assets (excluding Settlement Only Resources), Demand Response Resources, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demands with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply or consume 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 output 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.2.7A(c); and (5) the effect on transmission losses caused by the increment of load, generation and demand reduction. 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. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed for every five-minute interval, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the pricing 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.

### **III.2.6 Calculation of Nodal Day-Ahead 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, Demand Reduction 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 an optimization method to minimize energy cost, 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 output 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 supply. 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.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: 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 supply at the Generator Asset's Economic Maximum Limit and demand reduction at the Demand Response Resource's Maximum Reduction, 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, Demand Reduction 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 Generator Assets, dispatched Demand Response Resources, 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 Generator Assets (excluding Settlement Only Resources),

dispatched Demand Response Resources, 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 supply (including fixed External Transaction purchases) with all possible Generator Assets off line and with all remaining Generator Assets at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess 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 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 Generator Assets 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 Generator Assets (excluding Settlement Only Resources); and

(iii) If power balance not achieved in step (ii), set LMP values to Energy Offer Floor and reduce all Generator Assets 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 and DRR Aggregation Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone or DRR Aggregation Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and DRR Aggregation 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, Dispatch Zones, and Reserve Zones and add or subtract Reliability Regions, Load Zones, Dispatch 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 is greater than 75 percent of the total 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 obtain Operating Reserve in Real-Time to serve Operating Reserve requirements for the system and each Reserve Zone on a jointly optimized basis with the calculation of nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to maximize social surplus, 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 Generator Assets (excluding Settlement Only Resources), Demand Response Resources and Dispatchable Asset Related Demands 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 meet the system and zonal Operating Reserve requirements or there is a deficiency in available Operating Reserve, in which case Real-Time Reserve Clearing Prices shall be set as described in Section III.2.7A(b) and Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands that were re-dispatched to meet the applicable Operating Reserve requirement. The Real-Time Reserve Opportunity Cost of a Resource shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve.

(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 the following Reserve Constraint Penalty Factors:

<b>Real-Time Requirement</b>	<b>Reserve Constraint Penalty Factor</b>
Zonal Reserve Requirement (combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone)	\$250/MWh
Minimum Total Reserve Requirement (does not include Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	\$1000/MWh
Total Reserve Requirement (includes Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	\$250/MWh
Ten-Minute Reserve Requirement (combined amount of TMSR and TMNSR required system-wide)	\$1500/MWh

Ten-Minute Spinning Reserve Requirement (amount of TMSR required system-wide)	\$50/MWh
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The Reserve Constraint Penalty Factors 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 for every five-minute interval, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of zonal Real-Time Reserve Clearing Prices based on system conditions for the pricing 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.

### **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 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**

**Table of Contents**

- III.A.1. Introduction and Purpose: Structure and Oversight: Independence
  - III.A.1.1. Mission Statement
  - III.A.1.2. Structure and Oversight
  - III.A.1.3. Data Access and Information Sharing
  - III.A.1.4. Interpretation
  - III.A.1.5. Definitions
  
- III.A.2. Functions of the Market Monitor
  - III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor
  - III.A.2.2. Functions of the External Market Monitor
  - III.A.2.3. Functions of the Internal Market Monitor
  - III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions
    - III.A.2.4.1. Purpose
    - III.A.2.4.2. Conditions for the Imposition of Mitigation Measures
    - III.A.2.4.3. Applicability
    - III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*
    - III.A.2.4.5. Duration of Mitigation
  
- III.A.3. Consultation Prior to Determination of Reference Levels for Physical Parameters and Financial Parameters of Resources; Fuel Price Adjustments
  - III.A.3.1. Consultation Prior to Offer
  - III.A.3.2. Dual Fuel Resources
  - III.A.3.3. Market Participant Access to its Reference Levels
  - III.A.3.4. Fuel Price Adjustments
  
- III.A.4. Physical Withholding
  - III.A.4.1. Identification of Conduct Inconsistent with Competition



III.A.4.2. Thresholds for Identifying Physical Withholding

III.A.4.2.1. Initial Thresholds

III.A.4.2.2. Adjustment to Generating Capacity

III.A.4.2.3. Withholding of Transmission

III.A.4.2.4. Resources in Congestion Areas

III.A.4.3. Hourly Market Impacts

III.A.5. Mitigation

III.A.5.1. Resources with Capacity Supply Obligations

III.A.5.1.1. Resources with Partial Capacity Supply Obligations

III.A.5.2. Structural Tests

III.A.5.2.1. Pivotal Supplier Test

III.A.5.2.2. Constrained Area Test

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market

III.A.5.5. Mitigation by Type

III.A.5.5.1. General Threshold Energy Mitigation

III.A.5.5.1.1. Applicability

III.A.5.5.1.2. Conduct Test

III.A.5.5.1.3. Impact Test

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test

III.A.5.5.2. Constrained Area Energy Mitigation

III.A.5.5.2.1. Applicability

III.A.5.5.2.2. Conduct Test

III.A.5.5.2.3. Impact Test

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test

III.A.5.5.3. Manual Dispatch Energy Mitigation

III.A.5.5.3.1. Applicability

III.A.5.5.3.2. Conduct Test

III.A.5.5.3.3. Consequence of Failing the Conduct Test

III.A.5.5.4. General Threshold Commitment Mitigation

III.A.5.5.4.1. Applicability

III.A.5.5.4.2. Conduct Test

III.A.5.5.4.3. Consequence of Failing Conduct Test

- III.A.5.5.5. Constrained Area Commitment Mitigation
      - III.A.5.5.5.1. Applicability
      - III.A.5.5.5.2. Conduct Test
      - III.A.5.5.5.3. Consequence of Failing Test
    - III.A.5.5.6. Reliability Commitment Mitigation
      - III.A.5.5.6.1. Applicability
      - III.A.5.5.6.2. Conduct Test
      - III.A.5.5.6.3. Consequence of Failing Test
    - III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation
      - III.A.5.5.7.1. Applicability
      - III.A.5.5.7.2. Conduct Test
      - III.A.5.5.7.3. Consequence of Failing Conduct Test
    - III.A.5.5.8. Low Load Cost
  - III.A.5.6. Duration of Energy Threshold Mitigation
  - III.A.5.7. Duration of Commitment Mitigation
  - III.A.5.8. Duration of Start-Up Fee and No-Load Mitigation
  - III.A.5.9. Correction of Mitigation
  - III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process
- III.A.6. Physical and Financial Parameter Offer Thresholds
  - III.A.6.1. Time-Based Offer Parameters
  - III.A.6.2. Financial Offer Parameters
  - III.A.6.3. Other Offer Parameters
- 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 Parameter
  - III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Supply Offers
    - III.A.7.2.1. Order of Reference Level Calculation
    - III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation
  - III.A.7.3. Accepted Offer-Based Reference Level
  - III.A.7.4. LMP-Based Reference Level

- III.A.7.5. Cost-based Reference Level
  - III.A.7.5.1. Estimation of Incremental Operating Cost
- III.A.8. [Reserved.]
- III.A.9. Regulation
- III.A.10. Demand Bids
- III.A.11. Mitigation of Increment Offers and Decrement Bids
  - III.A.11.1. Purpose
  - III.A.11.2. Implementation
    - III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids
  - III.A.11.3. Mitigation Measures
  - III.A.11.4. Monitoring and Analysis of Market Design and Rules
- III.A.12. Cap on FTR Revenues
- 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
  - III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market
  - III.A.13.3. Monitoring of Transmission Facility Outage Scheduling
  - III.A.13.4. Monitoring of Forward Reserve Resources
  - III.A.13.5. Imposition of Sanctions
- III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement
- III.A.15. Request for Additional Cost Recovery
  - III.A.15.1. Filing Right
  - III.A.15.2. Contents of Filing
  - III.A.15.3. Review by Internal Market Monitor Prior to Filing
  - III.A.15.4. Cost Allocation

- III.A.16. ADR Review of Internal Market Monitor Mitigation Actions
  - III.A.16.1. Actions Subject to Review
  - III.A.16.2. Standard of Review
  
- III.A.17. Reporting
  - III.A.17.1. Data Collection and Retention
  - III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor
    - III.A.17.2.1. Monthly Report
    - III.A.17.2.2. Quarterly Report
    - III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market
    - III.A.17.2.4. Annual Review and Report by the Internal Market Monitor
  - III.A.17.3. Periodic Reporting by the External Market Monitor
  - III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications with Government Agencies
    - III.A.17.4.1. Routine Communications
    - III.A.17.4.2. Additional Communications
    - III.A.17.4.3. Confidentiality
  - III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators
  
- III.A.18. Ethical Conduct Standards
  - III.A.18.1. Compliance with ISO New England Inc. Code of Conduct
  - III.A.18.2. Additional Ethical Conduct Standards
    - III.A.18.2.1. Prohibition on Employment with a Market Participant
    - III.A.18.2.2. Prohibition on Compensation for Services
    - III.A.18.2.3. Additional Standards Application to External Market Monitor
  
- III.A.19. Protocols on Referrals to the Commission of Suspected Violations
  
- III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes

- III.A.21. Review of Offers From New Resources in the Forward Capacity Market
  - III.A.21.1. Offer Review Trigger Prices
    - III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction
    - III.A.21.1.2. Calculation of Offer Review Trigger Prices
  - III.A.21.2. New Resource Offer Floor Prices and Offer Prices
  - III.A.21.3. Special Treatment of Certain Out-of-Market Capacity Resources in the Eighth Forward Capacity Auction
- III.A.22. [Reserved]
- III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market
  - III.A.23.1. Pivotal Supplier Test
  - III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal
  - III.A.23.3. Pivotal Supplier Test Notification of Results
  - III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test
- III.A.24 Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market
- EXHIBIT 1 [Reserved]
- EXHIBIT 2 [Reserved]
- EXHIBIT 3 [Reserved]
- EXHIBIT 4 [Reserved]
- 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, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this *Appendix A*, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

### **III.A.3.2. Dual Fuel Resources.**

In evaluating bids or offers under this *Appendix A* for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

- (a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.
- (b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

### **III.A.3.3. Market Participant Access to its Reference Levels.**

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

### **III.A.3.4. Fuel Price Adjustments.**

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer



or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus \$2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1 or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2

2 or more	6
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#### **III.A.4. Physical Withholding.**

##### **III.A.4.1. Identification of Conduct Inconsistent with Competition.**

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

- (a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
- (b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,
- (c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
- (d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

##### **III.A.4.2. Thresholds for Identifying Physical Withholding.**

###### **III.A.4.2.1. Initial Thresholds.**

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

- (a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
- (b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

- (c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

#### **III.A.4.2.2. Adjustment to Generating Capacity.**

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

#### **III.A.4.2.3. Withholding of Transmission.**

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

#### **III.A.4.2.4. Resources in Congestion Areas.**

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

#### **III.A.4.3. Hourly Market Impacts.**

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

#### **III.A.5. Mitigation.**

##### **III.A.5.1. Resources with Capacity Supply Obligations.**

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

#### **III.A.5.1.1. Resources with Partial Capacity Supply Obligations.**

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

- (a) all Supply Offer parameters shall be reviewed for economic withholding;
- (b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;
- (c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

#### **III.A.5.2. Structural Tests.**

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

- (a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;
- (b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

##### **III.A.5.2.1. Pivotal Supplier Test.**

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

#### **III.A.5.2.2. Constrained Area Test.**

A Resource is considered to be within a constrained area if:

- (a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;
- (b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than \$25/MWh.

#### **III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.**

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

#### **III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.**

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

- (a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
- (b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

### **III.A.5.5. Mitigation by Type.**

#### **III.A.5.5.1. General Threshold Energy Mitigation.**

##### **III.A.5.5.1.1. Applicability.**

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

##### **III.A.5.5.1.2. Conduct Test.**

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or \$100/MWh, whichever is lower. Offer block prices below \$25/MWh are not subject to the conduct test.

##### **III.A.5.5.1.3. Impact Test.**

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or \$100/MWh, whichever is lower as determined by the real-time impact test.

##### **III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.**

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

### **III.A.5.5.2. Constrained Area Energy Mitigation.**

#### **III.A.5.5.2.1. Applicability.**

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

#### **III.A.5.5.2.2. Conduct Test.**

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or \$25/MWh, whichever is lower.

#### **III.A.5.5.2.3. Impact Test.**

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or \$25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

#### **III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.**

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

### **III.A.5.5.3. Manual Dispatch Energy Mitigation.**

#### **III.A.5.5.3.1. Applicability.**

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

#### **III.A.5.5.3.2. Conduct Test.**

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

#### **III.A.5.5.3.3. Consequence of Failing the Conduct Test.**

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

#### **III.A.5.5.4. General Threshold Commitment Mitigation.**

##### **III.A.5.5.4.1. Applicability.**

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

##### **III.A.5.5.4.2. Conduct Test.**

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

##### **III.A.5.5.4.3. Consequence of Failing Conduct Test.**

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

#### **III.A.5.5.5. Constrained Area Commitment Mitigation.**

##### **III.A.5.5.5.1. Applicability.**

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

##### **III.A.5.5.5.2. Conduct Test.**

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.



#### **III.A.5.5.3. Consequence of Failing Test.**

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

#### **III.A.5.5.6. Reliability Commitment Mitigation.**

##### **III.A.5.5.6.1. Applicability.**

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

- i. local first contingency;
- ii. local second contingency;
- iii. VAR or voltage;
- iv. distribution (Special Constraint Resource Service);
- v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

##### **III.A.5.5.6.2. Conduct Test.**

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

##### **III.A.5.5.6.3. Consequence of Failing Test.**

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

#### **III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.**

##### **III.A.5.5.7.1. Applicability.**

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

**III.A.5.5.7.2. Conduct Test.**

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

**III.A.5.5.7.3. Consequence of Failing Conduct Test.**

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

**III.A.5.5.8. Low Load Cost.**

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

- (a) If the Resource is starting from an offline state, the Start-Up Fee;
- (b) The sum of the No Load Fees for the Commitment Period; and
- (c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

### **III.A.5.6. Duration of Energy Threshold Mitigation.**

Any mitigation imposed pursuant to Sections III.A.5.5.1 “General Threshold Energy Mitigation” or III.A.5.5.2 “Constrained Area Energy Mitigation” is in effect for the following duration:

- (a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:
  - i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,
  - ii. for constrained area energy mitigation, the Resource is not located within a constrained area.
- (b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 “Constrained Area Energy Mitigation”), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 “Manual Dispatch Energy Mitigation” is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource’s Node.

### **III.A.5.7. Duration of Commitment Mitigation.**

Any mitigation imposed pursuant to Sections III.A.5.5.4 “General Threshold Commitment Mitigation”, III.A.5.5.5 “Constrained Area Commitment Mitigation”, or III.A.5.5.6 “Reliability Commitment Mitigation” is in effect for the duration of the Commitment Period.

### **III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.**

Any mitigation imposed pursuant to Sections III.A.5.5.7 “Start-Up Fee and No-Load Fee Mitigation” is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

### **III.A.5.9. Correction of Mitigation.**

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as

part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

#### **III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.**

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

#### **III.A.6. Physical and Financial Parameter Offer Thresholds.**

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

##### **III.A.6.1. Time-Based Offer Parameters.**

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

##### **III.A.6.2. Financial Offer Parameters.**

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

### **III.A.6.3. Other Offer Parameters.**

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

### **III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.**

#### **III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.**

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

- (a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.
- (b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.
- (c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

#### **III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Supply Offers.**

The Reference Levels for Start-Up Fees, No-Load Fees, and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

### **III.A.7.2.1. Order of Reference Level Calculation.**

The Internal Market Monitor will calculate a Reference Level for each offer block of a Supply Offer according to the following hierarchy, under which the first method that can be calculated is used:

- (a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
- (b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
- (c) cost-based Reference Levels pursuant to Section III.A.7.5.

### **III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.**

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

- (a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
- (b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
- (c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
- (d) For any Operating Day for which, during the previous 90 days:
  - (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
  - (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
  - (iii) The Market Participant submits a fuel price pursuant to Section III.A.3.4.

For the purposes of this subsection:

- i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.
  - ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.
  - iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.
  - iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.
- (e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.
- (f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:
  - (i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,
  - (ii) No-Load Fee or its corresponding fuel blends,
  - (iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,
  - (iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and
  - (v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

### **III.A.7.3. Accepted Offer-Based Reference Level.**

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

#### **III.A.7.4. LMP-Based Reference Level.**

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

#### **III.A.7.5. Cost-Based Reference Level.**

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant 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:

$(\text{incremental heat rate} * \text{fuel costs}) + (\text{emissions rate} * \text{emissions allowance price}) + \text{variable operating and maintenance costs} + \text{opportunity costs.}$

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:

$(\text{no-load fuel use} * \text{fuel costs}) + (\text{no-load emissions} * \text{emission allowance price})$   
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up:

$(\text{start-up fuel use} * \text{fuel costs}) + (\text{start-up emissions} * \text{emission allowance price}) + \text{start-up variable and maintenance costs} + \text{other start-up costs that are not fuel, emissions or variable and maintenance costs.}$

**III.A.8. [Reserved.]**

**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 the Energy Market as outlined below:

- (a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.
- (b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as:  $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$ . The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.
- (c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both).

The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

### **III.A.11. Mitigation of Increment Offers and Decrement Bids.**

#### **III.A.11.1. Purpose.**

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

#### **III.A.11.2. Implementation.**

##### **III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.**

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$$(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1.$$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

#### **III.A.11.3. Mitigation Measures.**

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs

in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

- (i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.
- (ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.
- (iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

#### **III.A.11.4. Monitoring and Analysis of Market Design and Rules.**

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

#### **III.A.12. Cap on FTR Revenues.**

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at

another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

### **III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.**

#### **III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.**

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

- (a) [Reserved].
- (b) Section III.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.
- (c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.
- (d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.
- (e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.
- (f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

#### **III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.**

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

#### **III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.**

*Appendix G* of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The

Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

**III.A.13.4. Monitoring of Forward Reserve Resources.**

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this *Appendix A*. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

**III.A.13.5. Imposition of Sanctions.**

*Appendix B* of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer *Appendix B* in accordance with the provisions thereof.

**III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.**

Article 5 of the form of Cost-of-Service Agreement in *Appendix I* to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

**III.A.15. Request for Additional Cost Recovery.**

**III.A.15.1. Filing Right.**

If either

(a) as a result of mitigation applied to a Resource under this *Appendix A* for all or part of one or more Operating Days, or

(b) in the absence of mitigation, despite having submitted a Supply Offer at the Energy Offer Cap,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for the hours of the Operating Day during which the Supply Offer was mitigated or during which the Resource was operated at the Energy Offer Cap, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having submitted a Supply Offer at the Energy Offer Cap, costs incurred for the duration of the period of time for which the Resource was operated at the Energy Offer Cap.

#### **III.A.15.2. Contents of Filing.**

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource exceeded the costs as reflected in the Supply Offer at the Energy Offer Cap; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

#### **III.A.15.3. Review by Internal Market Monitor Prior to Filing.**

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.

#### **III.A.15.4. Cost Allocation.**

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

#### **III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.**

##### **III.A.16.1. Actions Subject to Review.**

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in *Appendix D* to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.
- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

##### **III.A.16.2. Standard of Review.**

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.



### **III.A.17. Reporting.**

#### **III.A.17.1. Data Collection and Retention.**

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this *Appendix A*, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

- (a) the opportunity costs associated with Demand Reduction Offers;
- (b) the accuracy of Demand Response Baselines;
- (c) the method used to achieve a demand reduction, and;
- (d) the accuracy of metered demand reported to the ISO.

#### **III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.**

##### **III.A.17.2.1. Monthly Report.**

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

##### **III.A.17.2.2. Quarterly Report.**

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this *Appendix A* and analysis of such market data. Final versions of such reports shall be

disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this *Appendix A*.

**III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.**

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this *Appendix A*.

**III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.**

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market

Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

### **III.A.17.3. Periodic Reporting by the External Market Monitor.**

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of *Appendix A*. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

- (i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.
- (ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.
- (iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.
- (iv) Review and assessment of the effectiveness of *Appendix A* and the administration of *Appendix A* by the Internal Market Monitor for consistency and compliance with the terms of *Appendix A*.
- (v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the

report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

### **III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.**

#### **III.A.17.4.1. Routine Communications.**

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

#### **III.A.17.4.2. Additional Communications.**

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

- (a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;
- (b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;
- (c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,
- (d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

#### **III.A.17.4.3. Confidentiality.**

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

#### **III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.**

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets (“authorized government agencies”). With respect to state regulatory bodies and state attorneys general (“authorized state agencies”), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy.

Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

### **III.A.18. Ethical Conduct Standards.**

#### **III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.**

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as *Exhibit 5*.

#### **III.A.18.2. Additional Ethical Conduct Standards.**

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

##### **III.A.18.2.1. Prohibition on Employment with a Market Participant.**

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

##### **III.A.18.2.2. Prohibition on Compensation for Services.**

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

**III.A.18.2.3. Additional Standards Applicable to External Market Monitor.**

In addition to the standards referenced in the remainder of this Section 18 of *Appendix A*, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

**III.A.19. Protocols on Referral to the Commission of Suspected Violations.**

- (A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.
- (B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.
- (C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information
  - (1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);

- (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
  - (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
  - (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
  - (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;
  - (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
  - (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

**III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.**

- (A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.
- (B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.



- (C) The referral should be addressed to the Commission’s Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.
- (D) The referral is to include, but need not be limited to, the following information.
- (1) A detailed narrative describing the perceived market design flaw(s);
  - (2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;
  - (3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;
  - (4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.
- (E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

**III.A.21. Review of Offers From New Resources in the Forward Capacity Market.**

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

**III.A.21.1. Offer Review Trigger Prices.**

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8 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 Forward Capacity Auction.**

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the twelfth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2021) shall be as follows:

<b>Generating Capacity Resources</b>	
<b>Technology Type</b>	<b>Offer Review Trigger Price (\$/kW-month)</b>
combustion turbine	\$6.503
combined cycle gas turbine	\$7.856
on-shore wind	\$11.025

<b>Demand Capacity Resources - Commercial and Industrial</b>	
<b>Technology Type</b>	<b>Offer Review Trigger Price (\$/kW-month)</b>
Load Management and/or previously installed Distributed Generation	\$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	\$0.000

<b>Demand Capacity Resources – Residential</b>	
<b>Technology Type</b>	<b>Offer Review Trigger Price (\$/kW-month)</b>
Load Management	\$7.559
previously installed Distributed Generation	\$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	\$0.000

<b>Other Resources</b>	
All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus \$0.01/kW-month.

#### **III.A.21.1.2. Calculation of Offer Review Trigger Prices.**

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. 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 Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent

with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<b>Cost Component</b>	<b>Index</b>
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"
steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"

construction labor	BLS “Quarterly Census of Employment and Wages” 2371 Utility System Construction Average Annual Pay: <ul style="list-style-type: none"> <li>- Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</li> <li>- On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</li> </ul>
other labor	BLS “Quarterly Census of Employment and Wages” 2211 Power Generation and Supply Average Annual Pay: <ul style="list-style-type: none"> <li>- Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</li> <li>- On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</li> </ul>
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"
fuel inventories	Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<b>Cost Component</b>	<b>Index</b>
labor, administrative and general	BLS “Quarterly Census of Employment and Wages” 2211 Power Generation and Supply Average Annual Pay: <ul style="list-style-type: none"> <li>- Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</li> <li>- On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</li> </ul>
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”

(3) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 above will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub On-Peak electricity prices for the months in the Capacity Commitment Period beginning June 1, 2021, as published by ICE.

(5) Renewable energy credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

### **III.A.21.2. New Resource Offer Floor Prices and Offer Prices.**

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be \$0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated

with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by

state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and



supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

**III.A.22. [Reserved.]**

**III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.**

**III.A.23.1. Pivotal Supplier Test.**

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

- (a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;
- (b) For each modeled import-constrained Capacity Zone, the greater of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the

- capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
- (c) For each modeled export-constrained Capacity Zone, the lesser of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone plus, for each external interface connected to the export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Maximum Capacity Limit of the export-constrained Capacity Zone, and;
- (d) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

- (e) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone; and
- (f) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

### **III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.**

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

- (a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.
- (b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section

III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

- (c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
- (d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

### **III.A.23.3. Pivotal Supplier Test Notification of Results.**

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

### **III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.**

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Capacity Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a

supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

**III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.**

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

- i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than
- ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then
- iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

- iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.
- v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including

the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

- vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, “control” or “controlled” means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

**SECTION III**  
**MARKET RULE 1**

**APPENDIX F**  
**NET COMMITMENT PERIOD COMPENSATION ACCOUNTING**

**APPENDIX F**  
**NCPC ACCOUNTING**  
Table of Contents

III.F.1. General

III.F.2. NCPC Credits

III.F.2.1. Day-Ahead Energy Market NCPC Credits

III.F.2.1.1. Eligibility for Credit.

III.F.2.1.2. Settlement Period.

III.F.2.1.3. Eligible Quantity.

III.F.2.1.3.A Hourly Bid

III.F.2.1.4. Hourly Cost.

III.F.2.1.5. Hourly Revenue.

III.F.2.1.6. General Credit Calculation.

III.F.2.1.7. Credit Calculation for Fast Start Generators, Flexible DNE Dispatchable Generators, Fast Start Demand Response Resources and Binary Storage DARDs Based on Daily Starts, and for Continuous Storage Generator Assets and Continuous Storage DARDs.

III.F.2.2. Real-Time Energy Market NCPC Credits

III.F.2.2.1. Eligibility for Credit.

III.F.2.2.2. Real-Time Commitment NCPC Credits.

III.F.2.2.2.1. Settlement Period.

III.F.2.2.2.2. Eligible Quantity.

III.F.2.2.2.3. Interval Cost.

III.F.2.2.2.3.A Interval Bid.

III.F.2.2.2.4. Interval Revenue.

III.F.2.2.2.5. Credit Calculation for Generator Assets and Demand Response Resources.

III.F.2.2.2.6. [Reserved.]

III.F.2.2.2.7. Credit Calculation for Binary Storage DARDs.

III.F.2.2.2.8. Resources with Commitment in the Day-Ahead Energy Market.



- III.F.2.2.3. Real-Time Dispatch NCPC Credits for Generator Assets and Demand Response Resources.
  - III.F.2.2.3.1. Settlement Period.
  - III.F.2.2.3.2. Eligible Quantity.
  - III.F.2.2.3.3. Interval Cost.
  - III.F.2.2.3.4. Interval Revenue.
  - III.F.2.2.3.5. Credit Calculation.
- III.F.2.2.4. Real-Time Dispatch NCPC Credits for Storage DARDs.
  - III.F.2.2.4.1. Settlement Period.
  - III.F.2.2.4.2. Eligible Quantity.
  - III.F.2.2.4.3. Interval Cost.
  - III.F.2.2.4.4. Interval Bid.
  - III.F.2.2.4.5. Credit Calculation.
- III.F.2.2.5. Real-Time Dispatch Lost Opportunity Cost NCPC Credits.
  - III.F.2.2.5.1. Maximum Net Revenue or Maximum Net Benefit.
  - III.F.2.2.5.2. Actual Net Revenue or Actual Net Benefit.
  - III.F.2.2.5.3. Credit Calculation.
- III.F.2.3. Special Case NCPC Credit Calculations
  - III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits
  - III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits
  - III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)
  - III.F.2.3.4. [Reserved.]
  - III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits
  - III.F.2.3.6. Cancelled Start NCPC Credits
  - III.F.2.3.7. Hourly Shortfall NCPC Credits
  - III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability
  - III.F.2.3.9. Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured for Reliability and Demand Response Resources Postured for Reliability
  - III.F.2.3.10. Rapid Response Pricing Opportunity Cost NCPC Credits Resulting from Commitment of Rapid Response Pricing Assets

- III.F.2.4. Apportionment of NCPC Credits
- III.F.2.5. Credit Designation for Purposes of NCPC Cost Allocation
- III.F.3. Charges for NCPC
  - III.F.3.1 Cost Allocation
    - III.F.3.1.1 Day-Ahead Energy Market NCPC Cost Allocation
    - III.F.3.1.2 Real-Time Energy Market NCPC Cost Allocation
    - III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation
  - III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits
  - III.F.3.3 Local Second Contingency Protection Resource NCPC Charges
- III.F.4. NCPC Reporting

## NCPC ACCOUNTING

### III.F.1. General.

For purposes of NCPC calculations:

- a. Effective Offers.** An Effective Offer for a Resource is (1) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to commit the Resource and (2) the Supply Offer, Demand Reduction Offer, or Demand Bid used in making the decision to dispatch the Resource at a Desired Dispatch Point above its Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit, and is subject to the following conditions:
- i. The Effective Offer used in making the decision to commit the Resource establishes the parameters used for NCPC calculations, including the quantity and price pairs for output, demand reduction, or consumption up to the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit; the Start-Up Fee, No-Load Fee, or Interruption Cost; and the operating limits.
  - ii. In the event the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit is increased after the decision to commit the Resource, the energy price parameter for output, demand reduction, or consumption at the Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit used in making the decision to commit the Resource will be applied as the energy price parameter for additional output, demand reduction, or consumption up to the increased Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit.
  - iii. In the event a Minimum Generation Emergency is declared, the Economic Minimum Limit will be replaced with the Emergency Minimum Limit for purposes of determining the energy price parameter of the Effective Offer.
  - iv. The Effective Offer takes account of mitigation applied to the Supply Offer, whether performed prior to or after the commitment or dispatch decision is made.
  - v. The Effective Offer takes account of a reduction in the energy price parameter, the Start-Up Fee, the No-Load Fee, or the Interruption Cost in a Supply Offer or Demand Reduction Offer; or an increase in the energy price parameter of a Demand Bid that is made prior to the end of the Resource's Commitment Period.
  - vi. In the event the ISO approves the Resource's synchronization to the system as a Pool-Scheduled Resource earlier than its scheduled time, the Effective Offer takes account of the

- lesser of the energy price parameter, the Start-Up Fee and the No-Load Fee in place for the scheduled Commitment Period or the actual early release-for-dispatch time.
- vii. A Resource that is online providing synchronous condensing is considered to be in a hot temperature state for the purpose of determining the Start-Up Fee for the Effective Offer when the Resource is requested to switch from synchronous condensing to provide energy.
  - viii. The energy price parameter of the Effective Offer for a Demand Response Resource is the energy price parameter submitted in the Demand Reduction Offer, even where the Demand Reduction Threshold Price is used to clear the market pursuant to Section III.1.10.1A(e)(ii).

**b. Treatment of Self-Schedules.**

- i. In the Day-Ahead Energy Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to \$0, a No-Load Fee equal to \$0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to the minimum of the Energy Offer Floor and the Day-Ahead Price; or, in the case of a Storage DARD, is treated as having a Demand Bid with an energy price parameter for consumption up to its Minimum Consumption Limit equal to the maximum of the Energy Offer Cap and the Day-Ahead Price. Any amounts (MW) offered or bid above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid.
- ii. In the Real-Time Energy Market, a Resource that is committed as a Self-Schedule is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to \$0, a No-Load Fee equal to \$0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to \$0/MWh; or (ii) as having a Demand Bid for consumption up to the Minimum Consumption Limit at the Energy Offer Cap. Any amounts (MW) offered above the Economic Minimum Limit or Minimum Consumption Limit are evaluated based on the energy price parameters specified in the Supply Offer or Demand Bid. For any hour for which a Resource is dispatched pursuant to Section III.1.10.9(f), the Resource is treated either: (i) as having a Supply Offer with a Start-Up Fee equal to \$0, a No-Load Fee equal to \$0, and an energy price parameter for output up to the requested amount at the Energy Offer Floor; or (ii) as having a Demand Bid with an energy price parameter for consumption up to the requested amount at the Energy Offer Cap.
- iii. If the Resource's Supply Offer contains a Self-Schedule for fewer contiguous hours than its Minimum Run Time, the minimum number of additional hours required to satisfy the

Resource's Minimum Run Time will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market. If the Resource is committed for one or more hours immediately prior to and contiguous with the Self-Schedule, the hours of that prior Commitment Period will be counted toward satisfying the Resource's Minimum Run Time before hours subsequent to the Self-Schedule are counted. If the Resource's Supply Offer contains two Self-Schedules separated by less than the Resource's Minimum Down Time, the hours between the two Self-Schedules will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market.

- c. **Sub-Hourly Intervals.** If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.
- d. **Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Minimum Run Time or Minimum Reduction Time Carries Into Second Operating Day.** If a Resource that is committed in either (i) the Day-Ahead Energy Market, or (ii) the Reserve Adequacy Analysis prior to the start of the Operating Day must continue to operate across an Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for hour ending 24 of the Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day. If a Resource that is committed during the Operating Day must continue to operate across the Operating Day boundary to satisfy its Minimum Run Time or Minimum Reduction Time, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the second Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time or Minimum Reduction Time in the second Operating Day.
- e. **Supply Offers, Demand Reduction Offers, and Demand Bids Applicable When Committed Prior to Day-Ahead Energy Market.** If a Resource is committed for an Operating Day prior to the Day-Ahead Energy Market, the Supply Offer, Demand Reduction Offer, or Demand Bid in place for the Operating Day at the time of the commitment is used to establish the Effective Offer for the period of the commitment.
- f. **Eligibility for NCPC Credits When Performing Audits or Facility and Equipment Testing.** The Real-Time NCPC Credit calculation for a Resource performing an audit uses the Start-Up Fee, No-Load Fee, Interruption Cost, Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction in the Effective Offer applicable to the Commitment Period during which the

audit is conducted, and does not take account of any increases to the Economic Minimum Limit, Minimum Consumption Limit, or Minimum Reduction that take place in the course of the audit.

Market Participants are not eligible for NCPC Credits when conducting audits or Facility and Equipment Testing under the following conditions:

- i. When a Market Participant requests that some hours of the commitment of a Pool-Scheduled Resource be used to satisfy an audit, and the Market Participant has changed the Resource's Economic Minimum Limit, Minimum Reduction, or Minimum Consumption Limit for those hours for the purpose of conducting the audit, the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- ii. When a Market Participant Self-Schedules a Resource to perform the audit, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the Self-Schedule and is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- iii. When a Market Participant requests that an audit be performed that requires the ISO to dispatch the Resource for the audit without advance notice to the Market Participant, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment or Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted.
- iv. When an ISO-Initiated Claimed Capability Audit is performed pursuant to III.1.5.1.4, the Market Participant is not eligible for Real-Time Commitment NCPC Credits or Real-Time Dispatch NCPC Credits for the intervals during which the audit is conducted if both of the following are true:
  1. the Resource had a summer or winter Seasonal Claimed Capability or Seasonal DR Audit value equal to 0 MW at the beginning of the current Capability Demonstration Year, and
  2. the ISO Initiated Claimed Capability Audit is the first Claimed Capability Audit that the Resource performs during that Capability Demonstration Year.
- v. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Pool-Scheduled Resource, the Economic Minimum Limit (or Minimum Consumption Limit for a Binary Storage DARD) in place at the time of the commitment decision is used for

calculating Real-Time Commitment NCPC Credits and the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.

- vi. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Resource that Self-Scheduled, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment and is not eligible for Real-Time Dispatch NCPC Credits for the intervals during which the Facility and Equipment Testing is conducted.
- g. Coordinated External Transactions are Not Eligible for NCPC and are excluded from NCPC Charges.** Notwithstanding anything to the contrary in this Appendix F, Market Participants are not eligible to receive NCPC Credits for Coordinated External Transactions purchases or sales and shall be excluded from all NCPC Charge calculations under this Appendix F.
- h. Demand Response Resource Credit Calculations.** Where indicated in Section III.F.2, the costs and revenues for a Demand Response Resource, other than those associated with Net Supply or Interruption Costs, are increased by average avoided peak distribution losses.
- i. Following Dispatch Instructions.**
  - i. For the purpose of allocating NCPC costs, a Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit greater 50 MW is considered to be following a dispatch instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 10% above its Desired Dispatch Point and not less than 10% below its Desired Dispatch Point for each interval in the hour. A Resource with an Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit less than or equal to 50 MW is considered to be following a Dispatch Instruction if the actual output, demand reduction, or consumption of the Resource is not greater than 5 MW above its Desired Dispatch Point and is not less than 5 MW below its Desired Dispatch Point for each interval in the hour. If the Resource violates this criterion in any interval during the hour, the Resource is considered to be not following Dispatch Instructions for the entire hour.
  - ii. DNE Dispatchable Generators are considered to be following Dispatch Instructions if the actual output of the DNE Dispatchable Generator is at or below its Do Not Exceed Dispatch Point.

## **III.F.2. NCPC Credits**

### **III.F.2.1 Day-Ahead Energy Market NCPC Credits**

**III.F.2.1.1. Eligibility for Credit.** A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a Storage DARD with a Demand Bid that clear the Day-Ahead Energy Market in an hour is eligible for Day-Ahead Energy Market NCPC Credits for the hour.

**III.F.2.1.2. Settlement Period.** For a Generator Asset, a Demand Response Resource, or a Storage DARD, for purposes of calculating Day-Ahead Energy Market NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day for which a Resource has cleared in the Day-Ahead Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator or to or from a Fast Start Demand Response Resource, or any time a DNE Dispatchable Generator's operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation.

**III.F.2.1.3. Eligible Quantity.** For a Generator Asset, Demand Response Resource, or Storage DARD, the eligible quantity of energy is the amount of energy the Resource clears in the Day-Ahead Energy Market for each hour of the settlement period.

**III.F.2.1.3A Hourly Bid.** For a Storage DARD, the hourly bid is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each hour of the settlement period.

#### **III.F.2.1.4 Hourly Cost.**

- (a) For a Generator Asset, the hourly cost is equal to the energy price parameter for the eligible quantity, the Start-Up Fee and the No-Load Fee as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.
- (b) For a Demand Response Resource, the hourly cost is equal to the energy price parameter for the eligible quantity and the Interruption Cost as reflected in the Effective Offer for each hour of the settlement period, subject to Sections III.F.2.1.4.1 and III.F.2.1.4.2.
- (c) For a Storage DARD, the hourly cost is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity.



**III.F.2.1.4.1** For a Generator Asset or a Demand Response Resource, the Start-Up Fee or Interruption Cost is apportioned equally over the hours from the time the Resource is scheduled to begin its commitment through the end of the Commitment Period during which the Minimum Run Time or Minimum Reduction Time is scheduled to expire.

**III.F.2.1.4.2** For a Generator Asset or a Demand Response Resource, when the period of hours over which the Start-Up Fee or Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee or Interruption Cost.

**III.F.2.1.5 Hourly Revenue.** For a Generator Asset or a Demand Response Resource, the hourly revenue is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity for the Resource.

**III.F.2.1.6 General Credit Calculation.** Except as provided in Section III.F.2.1.7 below, the Day-Ahead Energy Market NCPC Credit for a Resource, adjusted as described in III.F.1(h), is equal to:

- (a) For a Generator Asset or a Demand Response Resource: the greater of (i) zero, and; (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly revenue for the Resource in all hours of the settlement period, where the costs and revenues of a Demand Response Resource, other than those associated with Interruption Costs, are increased by average avoided peak distribution losses; and
- (b) For a Binary Storage DARD: the greater of (i) zero and (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly bids in all hours of the settlement period.

**III.F.2.1.7 Credit Calculation for Fast Start Generators, Flexible DNE Dispatchable Generators, Fast Start Demand Response Resources and Binary Storage DARDs Based on Daily Starts, and for Continuous Storage Generator Assets and Continuous Storage DARDs.** If either (1) the number of daily starts for a Fast Start Generator, Flexible DNE Dispatchable Generator, Fast Start Demand Response Resource or Binary Storage DARD is less than the resource's Maximum Number of Daily Starts, or (2) the resource is a Continuous Storage Generator Asset or a Continuous Storage DARD, then the resource's Day-Ahead Energy Market NCPC Credit, adjusted as described in III.F.1(h), is calculated as follows:

- (a) For a Fast Start Generator, a Continuous Storage Generator Asset, a Flexible DNE Dispatchable Generator or a Fast Start Demand Response Resource, the Day-Ahead Energy Market NCPC Credit is

equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for the Resource in an hour minus the hourly revenue for the Resource in that hour.

- (b) For a Storage DARD, the Day-Ahead Energy Market NCPC Credit is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the total hourly cost for the Resource in an hour minus the total hourly bid for the Resource in that hour.

**III.F.2.2 Real-Time Energy Market NCPC Credits.** Real-Time Energy Market NCPC Credits include a Real-Time Commitment NCPC Credit, a Real-Time Dispatch NCPC Credit and a Real-Time Dispatch Lost Opportunity Cost NCPC Credit. For purposes of this Section III.F.2.2, unless otherwise expressly stated, costs and revenues shall be calculated at a five minute interval.

**III.F.2.2.1 Eligibility for Credit.**

- (a) Commitment Credits – The following Resources are eligible for Real-Time Commitment NCPC Credits for some or all intervals of the hour: (i) a Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market and that has been committed by the ISO; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; or (iii) a Binary Storage DARD with a Demand Bid that has been submitted in the Real-Time Energy Market and that has been committed by the ISO.
- (b) Dispatch Credits – The following Resources are eligible for Real-Time Dispatch NCPC Credits for some or all intervals of the hour: (i) a Generator Asset with a Supply Offer that has been submitted in the Real-Time Energy Market; (ii) a Demand Response Resource with a Demand Reduction Offer that has been submitted in the Real-Time Energy Market; (iii) a Storage DARD with a Demand Bid that has been submitted in the Real-Time Energy Market; or (iv) a Storage DARD that has been Postured to increase its consumption. The Real-Time Dispatch NCPC Credit shall be zero, however, if the Generator Asset has provided Regulation during the interval.
- (c) Dispatch Lost Opportunity Cost Credits – A Generator Asset with a Supply Offer, a Demand Response Resource with a Demand Reduction Offer, or a Dispatchable Asset Related Demand with a Demand Bid that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Real-Time Dispatch Lost Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Generator Asset, Demand Response Resource, or Dispatchable Asset Related Demand has been Postured or has provided Regulation during the interval.

**III.F.2.2.2 Real-Time Commitment NCPC Credits**

#### **III.F.2.2.2.1. Settlement Period.**

- (a) For Generator Assets, Demand Response Resources, and Binary Storage DARDs, for purposes of calculating Real-Time Commitment NCPC Credits, a settlement period is a period of one or more contiguous intervals in an Operating Day during which a Resource is operating pursuant to one or more commitments in the Day-Ahead Energy Market or Real-Time Energy Market.
  
- (b) For Generator Assets and Demand Response Resources, a new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.
  
- (c) For Generator Assets and Binary Storage DARDs, in the event of an interruption in operation of a Resource, operation will be considered contiguous if the Resource returns to operation in accordance with the original commitment issued prior to the interruption.

#### **III.F.2.2.2.2. Eligible Quantity.**

**III.F.2.2.2.2.A** For a Binary Storage DARD, the eligible quantity for each interval is the amount of energy equal to the lesser of its Economic Dispatch Point for that interval and its Metered Quantity For Settlement for the interval.

#### **III.F.2.2.2.2.1.**

- (a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy equal to the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval; provided however, that during contiguous pricing intervals in which the Generator Asset's Economic Dispatch Point is higher than it would otherwise be as a result of an offered ramp rate limitation, then the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy for the interval equal to the lesser of: (a) the Generator Asset's Metered Quantity For Settlement; and (b) the greater of: (i) the Generator Asset's expected output level had it reduced its output per its offered ramp rate during the relevant intervals as instructed by the ISO, and

(ii) the output level to which the Generator Asset would have been dispatched absent the offered ramp rate limitation.

- (b) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and Economic Dispatch Point for the interval, except that Metered Quantity For Settlement is used as the eligible quantity (i) when the Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) when the Resource is ramping from an offline state to be released for dispatch or (iii) after the Resource has been released for shutdown.

#### **III.F.2.2.2.2.**

- (a) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the lesser of the Resource's Metered Quantity For Settlement and its Economic Dispatch Point for the interval; provided however, that during contiguous pricing intervals in which the Demand Response Resource's Economic Dispatch Point is higher than it would otherwise be as a result of an offered ramp rate limitation, then the eligible quantity for determining the interval costs used in calculating a Real-Time Commitment NCPC Credit is the amount of energy for the interval equal to the lesser of: (a) the Demand Response Resource's Metered Quantity For Settlement; and (b) the greater of: (i) the Demand Response Resource's expected demand reduction had it provided the reduction per its offered ramp rate during the relevant intervals as instructed by the ISO, and (ii) the demand reduction level at which the Demand Response Resource would have been dispatched absent the offered ramp rate limitation.
- (b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Commitment NCPC Credit is equal to the eligible quantity used to determine interval costs pursuant to (a) above, except that the eligible quantity shall be the Metered Quantity For Settlement if any of the following are true: (i) the Demand Response Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the interval, (ii) the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time have not concluded, or (iii) the Demand Response Resource has received an instruction to stop reducing demand.

#### **III.F.2.2.2.3. Interval Cost.**

- (a) The interval cost for a Generator Asset is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Start-Up Fee and No-Load Fee as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1, III.F.2.2.2.3.2, and III.F.2.2.2.3.3.
- (b) The interval cost for a Demand Response Resource is equal to the energy price parameter submitted for the eligible quantity as reflected in the Effective Offer, and the Interruption Cost as reflected in the Effective Offer, for each interval of the settlement period, subject to Sections III.F.2.2.2.3.1 and III.F.2.2.2.3.2, provided that costs shall be set to \$0 for the interval when there is a negative demand reduction.
- (c) The interval cost for a Binary Storage DARD is the Real-Time Price for the interval multiplied by the eligible quantity. The interval cost is reduced by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval cost is also reduced by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5.

#### **III.F.2.2.2.3.1**

- (a) For a Generator Asset, the energy cost for an interval excludes the cost of (a) energy produced when the Resource is ramping from an offline state to be released for dispatch and (b) energy produced after the Resource has been released for shutdown.
- (b) For a Demand Response Resource, the energy cost for an interval excludes the cost of (a) energy produced prior to the conclusion of the Demand Response Resource Start-Up Time and (b) energy produced after the Demand Response Resource has received an instruction to stop reducing demand.

#### **III.F.2.2.2.3.2**

- (a) For a Generator Asset, the Start-Up Fee is apportioned equally over the intervals from the time the Generator Asset is released for dispatch through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire, subject to the following conditions:
  - (i) The Start-Up Fee is reduced in proportion to the number of minutes after 30 the Generator Asset is released for dispatch (measured from the time the Generator Asset was scheduled to be released for dispatch), divided by the time from when the Generator Asset was scheduled to be

released for dispatch through the end of the Commitment Period during which the Minimum Run Time was scheduled to expire.

- (ii) The Start-Up Fee is excluded from the interval cost calculation if the Generator Asset is synchronized to the system prior to its scheduled synchronization time without the ISO's approval of the Generator Asset's synchronization as a Pool-Scheduled Resource.
  - (iii) The portion of the Start-Up Fee apportioned to any interval during which the Generator Asset is not online because the Generator Asset has tripped is excluded from the interval cost calculation, except in the event the Generator Asset is not online due to a trip that results from equipment failure involving equipment located on the electric network beyond the low voltage terminals of the Generator Asset's step-up transformer. It is the responsibility of the Lead Market Participant for the Generator Asset to inform the ISO at [xtrip@iso-ne.com](mailto:xtrip@iso-ne.com) within 30 days that the trip was the result of such a transmission-related event.
  - (iv) The Start-Up Fee is not reduced when the Generator Asset has shutdown with the ISO's approval prior to the end of its Commitment Period.
  - (v) The additional Start-Up Fee for a Generator Asset requested to re-start following a trip is apportioned equally over the remaining intervals of the Commitment Period when the ISO requests a Generator Asset to re-start to complete its Commitment Period.
  - (vi) When the period of intervals over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.
- (b) For a Demand Response Resource, the Interruption Cost is apportioned equally over the intervals from the time the Demand Response Resource Start-Up Time concludes through the end of the Commitment Period during which the Minimum Reduction Time is scheduled to expire, subject to the following conditions:
- (i) The Interruption Cost is reduced in proportion to the number of minutes after 30 the Demand Response Resource begins to provide a demand reduction (measured from the conclusion of the Demand Response Resource Start-Up Time), divided by the time from the conclusion of the Demand Response Resource Start-Up Time through the end of the Commitment Period during which the Minimum Reduction Time was scheduled to expire.
  - (ii) The portion of the Interruption Cost apportioned to any interval during which the Demand Response Resource is not providing a demand reduction because the Demand Response Resource has become unavailable to provide a reduction is excluded from the interval cost calculation.
  - (iii) The Interruption Cost is not reduced when the Demand Response Resource has stopped reducing demand with the ISO's approval prior to the end of its Commitment Period. When the period of

intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.

- (iv) When the period of intervals over which the Interruption Cost is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Interruption Cost.

**III.F.2.2.2.3.3.** For a Generator Asset for each hour, the No-Load Fee is equally apportioned to each interval in the hour during the period when the Generator Asset is online following its release for dispatch and prior to its release for shutdown. The No-Load Fee is pro-rated for the hour during which the Generator Asset is released for dispatch, the hour during which the Generator Asset is released for shutdown, and any other hour during which the Generator Asset operates for less than 60 minutes.

**III.F.2.2.2.3.A Interval Bid.** The interval bid for a Binary Storage DARD is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer for each interval of the settlement period.

**III.F.2.2.2.4 Interval Revenue.** The interval revenue for a Generator Asset or Demand Response Resource is equal to the Real-Time Price for each interval of the settlement period multiplied by the eligible quantity for the interval. The revenue for an interval is increased by the amount by which the interval revenues in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.4 exceed the interval costs in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.3. The interval revenue is increased by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.3.10. The interval revenue is also increased by any Real-Time Dispatch Lost Opportunity Cost NCPC Credits calculated during the interval pursuant to Section III.F.2.2.5. The revenues when the Generator Asset is ramping from an offline state to be released for dispatch, or during the Demand Response Resource Start-Up Time, are apportioned equally to the intervals of the Minimum Run Time or Minimum Reduction Time.

**III.F.2.2.2.4.1.** For a Generator Asset, revenues for output up to the Resource's Economic Minimum Limit in a Self-Scheduled interval, calculated as the Real-Time Price multiplied by the output, are excluded from the revenue for the Real-Time Commitment NCPC Credit calculation.

**III.F.2.2.2.4.2.** For a Demand Response Resource, revenues shall be set to \$0 for the interval when the Locational Marginal Price is positive and there is a negative demand reduction.

**III.F.2.2.2.5 Credit Calculation for Generator Assets and Demand Response Resources.** The Real-Time Commitment NCPC Credit for a Generator Asset or a Demand Response Resource, adjusted as described in III.F.1(h) is equal to:

- (a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval revenue for the Resource for the period,  
plus,
- (b) For each remaining interval of the settlement period following the completion of the Minimum Run Time or Minimum Reduction Time, the greater of ((i) zero, and; (ii) the maximum potential net revenues for the Resource in the period) minus the actual net revenues for the Resource in the period, where
  - (i) The maximum potential net revenue is the maximum accumulated net interval revenue for operating and then shutting down (or, for a Demand Response Resource, reducing demand and then ceasing to reduce demand) during the period.
  - (ii) The actual net revenue is the accumulated net interval revenue over the period.
  - (iii) The net interval revenue is the interval revenues minus interval costs in the period.

**III.F.2.2.2.6. [Reserved.]**

**III.F.2.2.2.7 Credit Calculation for Binary Storage DARDs.** The Real-Time Commitment NCPC Credit for a Binary Storage DARD is equal to:

- (a) For the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time, the greater of (i) zero, and; (ii) the total interval cost for the Resource for the period minus the total interval bid for the Resource for the period,  
plus,



- (b) For each remaining interval of the settlement period following the completion of the Minimum Run Time, the greater of ((i) zero, and; (ii) the maximum potential net benefit for the Resource in the period) minus the actual net benefit for the Resource in the period, where
  - (i) The maximum potential net benefit is the maximum accumulated net interval benefit for operating and then shutting down during the period.
  - (ii) The actual net benefit is the accumulated net interval benefit over the period.
  - (iii) The net interval benefit is the interval bid minus interval cost in the period.

**III.F.2.2.2.8 Resources with Commitment in the Day-Ahead Energy Market (other than Fast Start Generators, Fast Start Demand Response Resources, and Binary Storage DARDs).**

- (a) For purposes of calculating the interval cost under Section III.F.2.2.2.3, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or Binary Storage DARD) has a commitment in the Day-Ahead Energy Market, the Start-Up Fee, No-Load Fee, Interruption Cost and energy price parameter for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to \$0 for the hour. The Start-Up Fee shall not be set to \$0 in the case when a Resource re-starts at ISO request following a trip.
- (b) For purposes of calculating the interval revenue under Section III.F.2.2.2.4, for any hour in which a Resource (other than a Fast Start Generator, Fast Start Demand Response Resource, or Binary Storage DARD) has a commitment in the Day-Ahead Energy Market, the revenue for output or demand reduction up to the Resource's Economic Minimum Limit or Minimum Reduction shall be set to \$0 for the hour if such revenue is less than \$0.
- (c) Notwithstanding anything to the contrary in this Section III.F.2.2.2, a Generator Asset that cleared in the Day-Ahead Energy Market and performs an audit scheduled by the ISO pursuant to Section III.1.5.2(f) during all or part of its Day-Ahead schedule on a higher-priced fuel than that which formed the basis of the Generator Asset's Supply Offer in the Day-Ahead Energy Market shall receive additional compensation equal to:
  - i. For the MW quantity equal to the lesser of the Generator Asset's actual metered output and Economic Dispatch Point, the difference between 1) the incremental energy audit costs based on the Supply Offer using the fuel on which the audit was performed and 2) amounts calculated for that same operation as reflected in the greater of the Day-Ahead Supply Offer and the cost-based Reference Levels calculated using the fuel on which the Day-Ahead Supply Offer was based; and
  - ii. The difference between the No-Load Fee based on the Supply Offer using the fuel on which the audit was performed and the No-Load Fee for that same operation as reflected in the Day-Ahead Supply Offer; and

iii. Any additional Start-Up Fees incurred as a result of performing the audit.

**III.F.2.2.3. Real-Time Dispatch NCPC Credits for Generator Assets and Demand Response Resources.**

**III.F.2.2.3.1 Settlement Period.**

- (a) Except as provided in Section III.F.2.2.3.1(b), for Generator Assets and Demand Response Resources, for purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement for a Resource are each greater than its Economic Dispatch Point, excluding any period of time when:
- i. For a Generator Asset, the generator is ramping from an offline state to be released for dispatch, and after the generator has been released for shutdown, or
  - ii. For a Demand Response Resource, prior to the conclusion of the Demand Response Start-Up Time and after the Demand Response Resource has received a Dispatch Instruction to stop reducing demand.
- (b) For a Continuous Storage Generator Asset associated with an ATRR that has provided Regulation during the interval, a settlement period is an interval when the Desired Dispatch Point is greater than the Economic Dispatch Point.

**III.F.2.2.3.2. Eligible Quantity.**

**III.F.2.2.3.2.1.**

- (a) For a Generator Asset, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Generator Asset's Economic Dispatch Point for the interval subtracted from the lesser of the Generator Asset's Metered Quantity For Settlement or Desired Dispatch Point for the interval, unless a Continuous Storage Generator Asset is associated with an ATRR that has provided Regulation during the interval, in which case the eligible quantity is the Generator Asset's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.
- (b) For a Demand Response Resource, the eligible quantity for determining the interval costs used in calculating a Real-Time Dispatch NCPC Credit is the Demand Response Resource's Economic

Dispatch Point for the interval subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement and its Desired Dispatch Point for the interval.

#### **III.F.2.2.3.2.2.**

- (a) For a Generator Asset, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit is the Generator Asset's Metered Quantity For Settlement for the interval minus the Generator Asset's Economic Dispatch Point, except that the Generator Asset's Economic Dispatch Point subtracted from the lesser of the Generator Asset's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval. Notwithstanding the foregoing, if a Continuous Storage Generator Asset is associated with an ATRR that has provided Regulation during the interval, the eligible quantity is the Generator Asset's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.
- (b) For a Demand Response Resource, the eligible quantity for determining the interval revenues used in calculating a Real-Time Dispatch NCPC Credit equals the Demand Response Resource's Metered Quantity For Settlement for the interval minus the Demand Response Resource's Economic Dispatch Point, except that the Demand Response Resource's Economic Dispatch Point subtracted from the lesser of the Demand Response Resource's Metered Quantity For Settlement or Desired Dispatch Point is used as the eligible quantity when the Real-Time Price is below zero for the interval.

**III.F.2.2.3.3 Interval Cost.** For a Generator Asset or a Demand Response Resource, the interval cost is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer and does not include the Start-Up Fee, the No-Load Fee, or the Interruption Cost.

**III.F.2.2.3.4 Interval Revenue.** For a Generator Asset or a Demand Response Resource, the interval revenue is equal to the Real-Time Price multiplied by the eligible quantity.

**III.F.2.2.3.5 Credit Calculation.** For a Generator Asset or a Demand Response Resource, the Real-Time Dispatch NCPC Credit in an interval is equal to the greater of (i) zero and (ii) the interval cost minus the interval revenue for the Resource, adjusted as described in III.F.1(h).

#### **III.F.2.2.4 Real-Time Dispatch NCPC Credits for Storage DARDs**

**III.F.2.2.4.1 Settlement Period.** For purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an interval when the Desired Dispatch Point and the Metered Quantity For Settlement are each greater than the Storage DARD's Economic Dispatch Point, unless a Continuous Storage DARD is associated with an ATRR that has provided Regulation during the interval, in which case a settlement period is an interval when the Desired Dispatch Point is greater than the Economic Dispatch Point.

**III.F.2.2.4.2 Eligible Quantity.** The eligible quantity of energy is equal to the greater of (i) zero and (ii) the Storage DARD's Economic Dispatch Point for the interval subtracted from the lesser of the Storage DARD's Metered Quantity For Settlement or Desired Dispatch Point for the interval, unless a Continuous Storage DARD is associated with an ATRR that has provided Regulation during the interval, in which case the eligible quantity is the DARD's Economic Dispatch Point for the interval subtracted from the Desired Dispatch Point for the interval.

**III.F.2.2.4.3 Interval Cost.** The interval cost is the Real-Time Price for the interval multiplied by the eligible quantity.

**III.F.2.2.4.4 Interval Bid.** The interval bid is equal to the energy price parameter for the eligible quantity as reflected in the Demand Bid for each interval of the settlement period.

**III.F.2.2.4.5 Credit Calculation.** The Real-Time Dispatch NCPC Credit for an eligible Storage DARD in an interval is equal to the greater of: (i) zero, and; (ii) the interval cost minus the interval bid in that interval.

### **III.F.2.2.5. Real-Time Dispatch Lost Opportunity Cost NCPC Credits**

#### **III.F.2.2.5.1. Maximum Net Revenue or Maximum Net Benefit.**

- (a) For a Generator Asset or a Demand Response Resource, the maximum net revenue during the interval is the Resource's energy revenue at the Economic Dispatch Point, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point, as described in III.F.1(h).
- (b) For a Dispatchable Asset Related Demand, the maximum net benefit during the interval is the Resource's energy price parameter for the Economic Dispatch Point as reflected in the Demand Bid, minus the offered energy cost for that quantity, plus the reserve revenue at the Economic Dispatch Point.

#### **III.F.2.2.5.2. Actual Net Revenue or Actual Net Benefit.**

- (a) The actual net revenue for a Generator Asset or Demand Response Resource shall be the sum, adjusted as described in III.F.1(h), of the following two values:
- (i) for a Continuous Storage Generator Asset associated with an ATRR that has provided Regulation during the interval, the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity; otherwise, the greater of: (1) the energy revenue at the Metered Quantity For Settlement minus the offered energy cost for that quantity and (2) the energy revenue at the dispatched energy quantity minus the offered energy cost for that quantity; and
  - (ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.
- (b) The actual net benefit for a Dispatchable Asset Related Demand shall be the sum of the following two values:
- (i) for a Continuous Storage DARD associated with an ATRR that has provided Regulation during the interval, the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity; otherwise, the greater of: (1) the energy price parameter for the Metered Quantity For Settlement as reflected in the Demand Bid minus the offered energy cost for that quantity and (2) the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid minus the offered energy cost for that quantity; and
  - (ii) the settled reserve quantity for the interval multiplied by the Real-Time Reserve Clearing Price.

**III.F.2.2.5.3. Credit Calculation.** For a Generator Asset, a Demand Response Resource, or a Dispatchable Asset Related Demand, the Real-Time Dispatch Lost Opportunity Cost NCPC Credit is equal to the greater of: (i) zero; and (ii) the Resource's maximum net revenue or benefit for the interval less its actual net revenue or benefit for the interval.

The Dispatch Lost Opportunity Cost NCPC Credit for a Resource for an interval shall be reduced by the amount of any Rapid Response Pricing Opportunity Cost NCPC Credits for which the Resource is eligible for that interval, but shall be no less than zero.

### **III.F.2.3. Special Case NCPC Credit Calculations**

#### **III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC**

## **Credits**

**III.F.2.3.1.1. Eligibility for Credit.** All Market Participants with pool-scheduled External Transaction imports or Increment Offers at an External Node are eligible for Day-Ahead External Transaction Import and Increment Offer NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

**III.F.2.3.1.2. Hourly Offer.** The Day-Ahead offer for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the offer price.

**III.F.2.3.1.3. Hourly Revenue.** The Day-Ahead revenue for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price.

**III.F.2.3.1.4. Credit Calculation.** A Day-Ahead External Transaction Import and Increment Offer NCPC Credit for an External Transaction import or Increment Offer, for an hour, is equal to any portion of the Day-Ahead offer in excess of the Day-Ahead revenue for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction import or Increment Offer for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction export or Decrement Bid for the same External Node and hour, the Day-Ahead External Transaction Import and Increment Offer NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction import or Increment Offer at the External Node for the hour that is not offset by the amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour. If multiple External Transaction imports or Increment Offers at an External Node are eligible for a Day-Ahead External Transaction Import and Increment Offer NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction imports and Increment Offers will be offset in order from the highest to the lowest-priced transactions or offers.

### **III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits**

**III.F.2.3.2.1. Eligibility for Credit.** All Market Participants with pool-scheduled External Transaction exports or Decrement Bids at an External Node are eligible for Day-Ahead External Transaction Export

and Decrement Bid NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

**III.F.2.3.2.2. Hourly Bid.** The Day-Ahead bid for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the bid price.

**III.F.2.3.2.3. Hourly Cost.** The Day-Ahead cost for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price at the External Node.

**III.F.2.3.2.4. Credit Calculation.** A Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for an External Transaction export or Decrement Bid, for an hour, is equal to any portion of the Day-Ahead hourly cost in excess of its Day-Ahead hourly bid for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction export or Decrement Bid for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction import or Increment Offer for the same External Node and hour, the Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour that is not offset by the amount (MW) of the total cleared External Transaction import or Increment Offer at the External Node for the hour. If multiple External Transaction exports or Decrement Bids at an External Node are eligible for a Day-Ahead External Transaction Export and Decrement Bid NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction exports and Decrement Bids will be offset in order from the lowest to the highest-priced transactions or bids.

### **III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)**

**III.F.2.3.3.1. Eligibility for Credit.** All Market Participants that submit pool-scheduled External Transactions (import or export) are eligible for Real-Time External Transaction NCPC Credits, with the exception of External Transactions to wheel energy through the New England Control Area.

**III.F.2.3.3.2. Eligible Quantity.**

- (a) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that either (i) did not clear in the Day-Ahead Energy Market, or (ii) cleared in the Day-Ahead Energy Market and the price was subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction.
- (b) For each interval, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that cleared in the Day-Ahead Energy Market and the price was not subsequently revised in the Re-Offer Period, is the Metered Quantity For Settlement for the External Transaction in excess of the cleared Day-Ahead scheduled transaction amount.

**III.F.2.3.3.3. Hourly Offer.** The hourly offer for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval offer, which is calculated by multiplying the eligible quantity by the offer price for the interval.

**III.F.2.3.3.4. Hourly Revenue.** The hourly revenue for a pool-scheduled External Transaction import for an hour is equal to the sum of the interval revenue, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

**III.F.2.3.3.5. Hourly Bid.** The hourly bid for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval bid, which is calculated by multiplying the eligible quantity by the bid price for the interval.

**III.F.2.3.3.6. Hourly Cost.** The Real-Time cost for a pool-scheduled External Transaction export for an hour is equal to the sum of the interval cost, which is calculated by multiplying the eligible quantity by the Real-Time Price for the interval.

**III.F.2.3.3.7. Credit Calculation.** A Real-Time External Transaction NCPC Credit for an External Transaction import for an hour is equal to any portion of the hourly offer in excess of the hourly revenue. A Real-Time External Transaction NCPC Credit for an External Transaction export for an hour is equal to any portion of the hourly cost in excess of the hourly bid.

**III.F.2.3.4. [Reserved.]**

**III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits**



**III.F.2.3.5.1. Eligibility for Credit.** A Resource that is dispatched as a Synchronous Condenser is eligible for Real-Time Synchronous Condensing NCPC Credits.

**III.F.2.3.5.2. Condensing Offer Amount.** The condensing offer amount for a Resource is equal to the number of hours that the Resource is dispatched as a Synchronous Condenser in an Operating Day multiplied by the hourly price to condense as specified in the Offer Data for the Resource. For a Resource committed from an offline state to provide synchronous condensing, the condensing offer amount includes the condensing start-up fee as specified in the Offer Data for the Resource. In the event an hourly price to condense or condensing start-up fee is not included in the Offer Data for the Resource for the hours that the Resource is dispatched as a Synchronous Condenser, the value for the parameter will be zero.

**III.F.2.3.5.3. Credit Calculation.** The Real-Time Synchronous Condensing NCPC Credit for a Resource for an Operating Day is equal to the condensing offer amount for that Operating Day.

#### **III.F.2.3.6. Cancelled Start NCPC Credits**

**III.F.2.3.6.1. Eligibility for credit.** A Pool-Scheduled Generator Asset or Demand Response Resource is eligible for a Cancelled Start NCPC Credit if the ISO cancels its commitment of the Pool-Schedule Resource before a Generator Asset is synchronized to the New England Transmission System, or before a Demand Response Resource has completed its Demand Response Resource Notification Time, except that a Market Participant is not eligible for a credit under the following conditions:

- (a) The start is cancelled before the commencement of the Notification Time or the Demand Response Resource Notification Time;
- (b) The Resource's Notification Time or Demand Response Resource Notification Time as reflected in the Effective Offer is equal to or greater than 24 hours;
- (c) The Generator Asset is synchronized to the New England Transmission System for a Self-Schedule within the period of time equal to the lesser of its Minimum Down Time or 10 hours after receiving the ISO cancelled start order; or
- (d) The Generator Asset fails to meet its scheduled synchronization time and the ISO cancelled start order is issued more than two hours after the Resource's scheduled synchronization time.

**III.F.2.3.6.2. Credit Calculation.** The Cancelled Start NCPC Credit for a Resource is equal to the Start-Up Fee or Interruption Cost reflected in the Effective Offer multiplied by the percentage of the Notification Time or Demand Response Resource Notification Time, as reflected in the Effective Offer, that the Resource completed prior to the ISO cancelled start order, where:

- (a) The percentage of Notification Time or Demand Response Notification Time completed is equal to the number of minutes after the start of the Notification Time or Demand Response Notification Time the Resource was cancelled divided by the Notification Time or Demand Response Notification Time, and cannot exceed 100%.

**III.F.2.3.7. Hourly Shortfall NCPC Credits**

**III.F.2.3.7.1. Eligibility for Credit.** A Generator Asset, Demand Response Resource, or Binary Storage DARD that is pool-scheduled in the Day-Ahead Energy Market is eligible for Hourly Shortfall NCPC Credits for an hour if the ISO (1) cancels its commitment of a non-Fast Start Generator, a non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator; or (2) does not dispatch a Fast Start Generator, a Fast Start Demand Response Resource, a Binary Storage DARD, or a Flexible DNE Dispatchable Generator for the hour; and (3) either the Generator Asset or Binary Storage DARD is offline and available for operation and the Generator Asset associated with the DARD is not supplying electricity to the grid, or the Demand Response Resource has not been dispatched and is available for operation; except that (4) a Market Participant is not eligible for a credit under the following conditions:

- (a) The Resource has been Postured for all or part of the hour;
- (b) The Resource is a Limited Energy Resource that has been Postured during a prior hour in the Operating Day; or
- (c) The Resource is an Intermittent Power Resource that is not a DNE Dispatchable Generator.

**III.F.2.3.7.2. Settlement Period.** For purposes of calculating Hourly Shortfall NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is eligible for an Hourly Shortfall NCPC Credit. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, to or from a Flexible DNE Dispatchable Generator, or to or from a Fast Start Demand Response Resource, and the Resource is committed with the changed designation.

**III.F.2.3.7.3. Eligible Quantity.** The eligible quantity for each hour of the settlement period is:

- (a) zero for a Fast Start Generator, a Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter, the Start-Up Fee and the No-Load Fee of the Supply Offer, or the total of the energy price parameter and the Interruption Cost of the Demand Reduction Offer, in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market for the hour is greater than the total of the corresponding energy price, Start-Up Fee, No Load Fee, and Interruption Cost parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;
  - i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9(e), the Start-Up Fee, No-Load Fee and energy at the Economic Minimum Limit are equal to \$0, and (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9(f), the Start-Up Fee and No-Load Fee are equal to \$0 and the energy at the requested dispatch level is the Energy Price Floor.
- (b) zero for a Binary Storage DARD in the event the energy price parameter in the Demand Bid in the Real-Time Energy Market for the consumption cleared in the Day-Ahead Energy Market for the hour is less than the energy price parameter in the Demand Bid in the Day-Ahead Energy Market for the hour.
  - i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9 (e), then the energy price at the Minimum Consumption Limit is equal to the Energy Offer Cap, and; (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9 (f), then the energy price at the requested dispatch level for Binary Storage DARDs is the Energy Offer Cap.
- (c) the Day-Ahead Economic Minimum Limit or Minimum Reduction for a non-Fast Start Generator, non-Fast Start Demand Response Resource, or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter of the Supply Offer or Demand Reduction Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market above the Day-Ahead Economic Minimum Limit or Day-Ahead Minimum Reduction for an hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

and if neither (a) nor (b) nor (c) applies, then;

(d) the minimum of (i) the amount of energy cleared in the Day-Ahead Energy Market for an hour and (ii) the Resource's Economic Maximum Limit, Maximum Reduction, or a Limited Energy Resource limit imposed for the hour in the Real-Time Energy Market.

**III.F.2.3.7.4. Credit Calculation (for non-Fast Start Generators, non-Fast Start Demand Response Resources, and non-Flexible DNE Dispatchable Generators).** The Hourly Shortfall NCPC Credit for a Resource, other than a Fast Start Generator, a Fast Start Demand Response Resource, a Binary Storage DARD, or a Flexible DNE Dispatchable Generator, adjusted as described in III.F.1(h), is equal to:

(a) the greater of (i) zero and (ii) the total of (the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the Day-Ahead Economic Minimum Limit for the hour or the Day-Ahead Minimum Reduction for the hour) for all hours of the settlement period,

plus

(b) for each hour of the settlement period, for Generator Assets, the greater of (i) zero and (ii) the product of (1) the Real-Time Price minus the Day-Ahead Price for an hour and (2) the eligible quantity minus the Day-Ahead Economic Minimum Limit for the hour; or, for Demand Response Resources, the greater of (i) zero and (ii) the product of (1) the Real Time Price minus the Day-Ahead Price for an hour and (2) the eligible quantity minus the Day-Ahead Minimum Reduction for the hour.

**III.F.2.3.7.5. Credit Calculation (for Fast Start Generators, Fast Start Demand Response Resources and Flexible DNE Dispatchable Generators).** The Hourly Shortfall NCPC Credit for a Fast Start Generator, Fast Start Demand Response Resource, or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and (ii) the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the eligible quantity for the hour, adjusted as described in III.F.1(h).

**III.F.2.3.7.6 Credit Calculation (for Binary Storage DARDs).** The Hourly Shortfall NCPC Credit for a Binary Storage DARD is equal to, for each hour of the settlement period, the greater of: (i) zero, and; (ii) the Day-Ahead Price minus the Real-Time Price for an hour, multiplied by the eligible quantity for the hour.

### **III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability**

**III.F.2.3.8.1. Eligibility for Credit.** A Limited Energy Resource is eligible for real-time posturing NCPC credits for any Operating Day during which the Generator Asset has been Postured, when a request to minimize the as-bid production costs of the Generator Asset has been submitted. For purposes of calculating real-time posturing NCPC credits, the Generator Asset is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Generator Asset was Postured, and if not the Generator Asset is treated as a non-Fast Start Generator. If the Generator Asset is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

**III.F.2.3.8.2. Settlement Period.** For purposes of calculating real-time posturing NCPC credits for Limited Energy Resources, a settlement period is the period of one or more contiguous hours from the initiation of Posturing through the end of the Operating Day.

**III.F.2.3.8.3 Resources Sharing a Single Fuel Source.** When Limited Energy Resources that share a fuel source are Postured, for purposes of calculating real-time posturing NCPC credits the energy available to the Postured Generator Assets will be allocated among the Postured Generator Assets sharing the fuel source as indicated by estimates of available energy provided by the Lead Market Participant for each Generator Asset prior to Posturing.

**III.F.2.3.8.4. Estimated Replacement Cost of Energy.** The estimated replacement cost of energy is (i) the average of the Day-Ahead Prices for hours ending 3 through 5 in the subsequent Operating Day for a Generator Asset that is part of an Electric Storage Facility, or (ii) the product of the oil index price multiplied by the oil-fired generator proxy heat rate for fuel oil-fired generating units, or (iii) zero for all other Generator Assets.

For fuel oil-fired generators, the oil index price is the ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation, and the oil-fired generator proxy heat rate is the average of the heat rate at Economic Min and the heat rate at Economic Max, where the heat rate at Economic Min is, for a Generator Asset, the average hourly energy price parameter of the Supply Offer at the Generator Asset's Economic Minimum Limit at the time of the Posturing decision divided by the oil index price, and the heat rate at Economic Max is, for a Generator Asset, the

average hourly energy price parameter of the Supply Offer at the Generator Asset's Economic Maximum Limit at the time of the Posturing decision divided by the oil index price.

**III.F.2.3.8.5. Estimated Revenue.** The estimated revenue for a Generator Asset is the optimized energy output multiplied by the Real-Time Price for all hours in the settlement period. The optimized energy output is estimated for each hour by allocating the Postured energy to hours that the Generator Asset would have operated had it not been Postured based on Real-Time Prices in the Operating Day, subject to the following conditions:

- (a) the optimized energy output determination will take account of the Generator Asset's Economic Minimum Limit, and Economic Maximum Limit.
- (b) the optimized energy output determination will take account of the estimated avoided cost of replacing energy that is not allocated to any hour and remains available at the end of the Operating Day.
- (c) for non-Fast Start Generators, the optimized energy output is calculated for the contiguous hours from the time the Generator Asset is Postured until the available energy is depleted.

**III.F.2.3.8.6. Estimated Avoided Replacement Cost.** The estimated avoided replacement cost for an Operating Day is the remaining energy that would have been available at the end of the Operating Day had the Generator Asset operated in accordance with the optimized energy output determination in Section III.F.2.3.8.5, plus any increase in the remaining energy resulting from replenishment during the Operating Day after the Generator Asset is Postured, multiplied by the estimated replacement cost of energy.

**III.F.2.3.8.7. Actual Revenue.** The actual revenue for a Generator Asset is the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the settlement period.

**III.F.2.3.8.8. Actual Avoided Replacement Cost.** The actual avoided replacement cost for an Operating Day is the actual remaining energy at the end of the Operating Day multiplied by the estimated replacement cost of energy.

**III.F.2.3.8.9. Credit Calculation.** The real-time posturing NCPC credit for Limited Energy Resources is equal to the greater of (i) zero and (ii) the estimated revenue plus the estimated avoided replacement cost, minus the actual revenue plus the actual avoided replacement cost.

**III.F.2.3.9. Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured for Reliability and for Demand Response Resources Postured for Reliability**

**III.F.2.3.9.1. Eligibility for Credit.** Generator Assets (other than Limited Energy Resources) and Demand Response Resources are eligible for real-time posturing NCPC credits for the hours during which the Resource has been Postured.

**III.F.2.3.9.2. Settlement Period.** For purposes of calculating real-time posturing NCPC credits, a settlement period is an hour during which the Generator Asset or Demand Response Resource is Postured.

**III.F.2.3.9.3. Offer Used for Estimated Hourly Revenue and Cost.**

- (a) For a Generator Asset, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:
- (i) Energy Price: the higher of the energy price parameter specified in (1) the Supply Offer for the hour at the time the ISO Postures the Generator Asset, or (2) the Supply Offer for the hour at the start of the hour;
  - (ii) Start-Up Fee and No Load Fee: for Generator Assets Postured offline, the Start-Up Fee and No-Load Fee specified in the Supply Offer for the hour at the time the Generator Asset is Postured;
  - (iii) for Generator Assets Postured to remain online but reduce output, the Start-Up Fee and No-Load Fee are calculated pursuant to Section III.F.2.2.2.3.
- (b) For a Demand Response Resource, the offer parameters used to estimate revenue and cost for an hour for purposes of calculating real-time posturing NCPC credits are:
- (i) Energy Price: the higher of the energy price parameter specified in (1) the Demand Reduction Offer for the hour at the time the ISO Postures the Resource, or (2) the Demand Reduction Offer for the hour at the start of the hour;
  - (ii) Interruption Cost: for a Demand Response Resource Postured to a demand reduction of zero MW, the Interruption Cost specified in the Demand Reduction Offer for the hour at the time the Demand Response Resource is Postured; for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MW, the Interruption Cost is calculated pursuant to Section III.F.2.2.2.3.

#### **III.F.2.3.9.4. Estimated Hourly Revenue.**

- (a) The estimated hourly revenue for a Generator Asset is the optimized energy output multiplied by the Real-Time Price for the hour. The optimized energy output is estimated for each hour by determining where the Generator Asset would have operated had it not been Postured based on Real-Time Prices. The optimized energy output determination will take account of the energy price parameter of the Supply Offer and the Generator Asset's Economic Minimum Limit and Economic Maximum Limit.
- (b) The estimated hourly revenue for a Demand Response Resource is the optimized demand reduction multiplied by the Real-Time Price for the hour, where:
  - (i) The optimized demand reduction is estimated for each hour by determining where the Demand Response Resource would have operated had it not been Postured based on Real-Time Prices. The optimized demand reduction determination will take account of the energy price parameter of the Demand Reduction Offer and the Demand Response Resource's Minimum Reduction and Maximum Reduction.

#### **III.F.2.3.9.5. Estimated Hourly Cost.**

- (a) The estimated hourly cost for a Generator Asset is the energy price parameter of the Supply Offer for the optimized energy output for the hour, plus the Start-Up Fee and the No-Load Fee, subject to the following conditions:
  - (i) For a Fast Start Generator Postured offline, the Start-Up Fee is included in each hour's cost and is not subject to apportionment;
  - (ii) For a non-Fast Start Generator Postured offline, the Start-Up Fee is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.
- (b) The estimated hourly cost for a Demand Response Resource is the energy price parameter of the Demand Reduction Offer for the optimized demand reduction for the hour (where optimized demand reduction is determined pursuant to Section III.F.2.3.9.4(b)), plus the Interruption Cost, subject to the following conditions:
  - (i) For a Fast Start Demand Response Resource Postured to a demand reduction level of zero MW, the Interruption Cost is included in each hour's cost and is not subject to apportionment;
  - (ii) For a non-Fast Start Demand Response Resource Postured to a demand reduction of greater than zero MW, the Interruption Cost is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.
- (c) A Generator Asset is treated as a Fast Start Generator and a Demand Response Resource is treated as a Fast Start Demand Response Resource for purposes of determining the estimated hourly cost only if it is designated as such at the time of the commitment decision for the Commitment Period during



which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator or non-Fast Start Demand Response Resource. If at the time the Resource is Postured the Generator Asset is offline, or the Demand Response Resource has not been dispatched, then its designation as a Fast Start Generator or Fast Start Demand Response Resource is determined as of the time of the Posturing decision.

**III.F.2.3.9.6. Actual Hourly Revenue.** The actual hourly revenue for a Generator Asset or a Demand Response Resource is the sum of the Metered Quantity For Settlement multiplied by the Real-Time Price for all intervals in the hour.

**III.F.2.3.9.7. Actual Hourly Cost.**

- (a) The actual hourly cost for a Generator Asset Postured to remain online but reduce output is the sum of the interval cost, which is the energy price parameter of the Supply Offer for the Metered Quantity For Settlement for the interval, plus the Start-Up Fee and No-Load Fee calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Generator Asset Postured offline is zero.
- (b) The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to a level greater than zero MW is the sum of the interval cost, which is the energy price parameter of the Demand Reduction Offer for the Metered Quantity For Settlement for the interval, plus the Interruption Cost calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Demand Response Resource Postured to reduce its demand reduction to zero MW is zero.

**III.F.2.3.9.8. Credit Calculation.** The real-time posturing NCPC credit for a Generator Asset (other than a Limited Energy Resource) or a Demand Response Resource is equal to the greater of (i) zero and (ii) the estimated hourly revenue minus the estimated hourly cost, minus the actual hourly revenue minus actual hourly cost, adjusted as described in III.F.1(h).

**III.F.2.3.10. Rapid Response Pricing Opportunity Cost NCPC Credits Resulting from Commitment of Rapid Response Pricing Assets**

**III.F.2.3.10.1. Eligibility for Credit.** During any five-minute pricing interval in which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, any Resource that is committed and able to respond to Dispatch Instructions during the interval is eligible to receive a Rapid Response Pricing Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Resource is non-dispatchable; the Resource has been Postured or has provided Regulation during the interval; if the

Resource is a Settlement Only Resource, or if the Resource is an External Resource or External Transaction.

**III.F.2.3.10.2. Economic Net Revenue or Economic Net Benefit.**

- (a) The economic net revenue for a Generator Asset or Demand Response Resource during the pricing interval is the Resource's optimized feasible energy quantity multiplied by the Real-Time Price, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.
- (b) The economic net benefit for a Dispatchable Asset Related Demand during the pricing interval is the Resource's energy price parameter for its optimized feasible energy quantity as reflected in its Demand Bid, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the optimized feasible energy quantity multiplied by the Real-Time Price.
- (c) The optimized feasible energy and reserve quantities are determined consistent with the Resource's offer or bid parameters, and are the energy and reserve quantities that maximize the Resource's economic net revenue or economic net benefit for the pricing interval, without changing the Resource's commitment status.

**III.F.2.3.10.3. Actual Net Revenue or Actual Net Benefit.**

- (a) Except as provided in Section III.F.2.3.10.3(b), the actual net revenue for a Generator Asset or Demand Response Resource is the greater of: (i) the actual energy quantity supplied during the pricing interval multiplied by the Real-Time Price, plus the actual reserve quantity supplied during the pricing interval multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities; and (ii) the dispatched energy quantity multiplied by the Real-Time Price, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.
- (b) The actual net revenue for a Generator Asset associated with an ATRR that has provided Regulation during the interval is equal to the dispatched energy quantity multiplied by the Real-Time Price, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.
- (c) Except as provided in Section III.F.2.3.10.3(d), the actual net benefit for a Dispatchable Asset Related Demand is the greater of: (i) the energy price parameter for the actual energy quantity consumed as reflected in the Demand Bid, plus the actual reserve quantity supplied multiplied by the Real-Time Reserve Clearing Price, minus the actual energy quantity consumed multiplied by the Real-Time Price, and (ii) the energy price parameter for the dispatched energy quantity as reflected in the

Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.

- (d) The actual net revenue for a DARD associated with an ATRR that has provided Regulation during the interval is equal to the energy price parameter for the dispatched energy quantity as reflected in the Demand Bid, plus the designated reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the dispatched energy quantity multiplied by the Real-Time price.

**III.F.2.3.10.4. Credit Calculation.** The real-time Rapid Response Pricing Opportunity Cost NCPC Credit for a Resource is equal to the greater of: (i) zero; and (ii) the Resource's economic net revenue or economic net benefit for the interval less its actual net revenue or actual net benefit for the pricing interval.

**III.F.2.4. Apportionment of NCPC Credits.** For purposes of this Section III.F.2.4, any values previously established at the five minute level shall be aggregated to create hourly values.

Each Day-Ahead Energy Market NCPC Credit calculated pursuant to III.F.2.1.6 is apportioned to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue for all hours in the settlement period.

Each Real-Time Commitment NCPC Credit is apportioned as follows: (i) for the portion of each Commitment Period within a settlement period that contains intervals of the Minimum Run Time or Minimum Reduction Time, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the portion of the Commitment Period, and (ii) for all remaining intervals of the settlement period, to the intervals with negative net revenues in proportion to each interval's negative net revenue divided by the sum of the negative net revenue in the period.

Each Hourly Shortfall NCPC Credit for a non-Fast Start Generator, a non-Fast Start Demand Response Resource or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator for energy cleared in the Day-Ahead Energy Market at the Resource's Economic Minimum Limit or Minimum Reduction is apportioned to the hours in which the Real-Time Price exceeds the Day-Ahead Price, for all hours in the settlement period.

The following NCPC credits are assigned to the hours for which the credit was calculated:

- Day-Ahead Energy Market NCPC Credits calculated pursuant to Section III.F.2.1.7.
- Real-Time Dispatch Lost Opportunity Cost NCPC Credits,
- Real-Time Dispatch NCPC Credits for all Resources,
- Day-Ahead External Transaction Import and Increment Offer NCPC Credits,
- Day-Ahead External Transaction Export and Decrement Bid NCPC Credits,
- Real-Time External Transaction NCPC Credits,
- Hourly Shortfall NCPC Credits for Fast Start Generators, Fast Start Demand Response Resources, Binary Storage DARDs and Flexible DNE Dispatchable Generators,
- Hourly Shortfall NCPC Credits for non-Fast Start Generators, non-Fast Start Demand Response Resources, and DNE Dispatchable Generators that are not Flexible DNE Dispatchable Generators for energy cleared in the Day-Ahead Energy Market above the Resource's Economic Minimum Limit or Minimum Reduction, and
- Rapid Response Pricing Opportunity Cost NCPC Credits as described in Section III.F.2.3.10.

**III.F.2.5. NCPC Credit Designation for Purposes of NCPC Cost Allocation.** Each hourly credit for Day-Ahead Energy Market NCPC Credits, Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Real-Time Dispatch Lost Opportunity Cost NCPC Credits, Day-Ahead External Transaction Import and Increment Offer NCPC Credits, Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, Real-Time External Transaction NCPC Credits, Hourly Shortfall NCPC Credits, and Real-Time Posturing NCPC Credits for Generator Assets (Other Than Limited Energy Resources) Postured For Reliability and Demand Response Resources Postured For Reliability, and each daily credit for Real-Time Synchronous Condensing NCPC Credits, Cancelled Start NCPC Credits, Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability, and Rapid Response Pricing Opportunity Cost NCPC Credit is designated as first contingency, second contingency, voltage (VAR), distribution (SCR), ISO initiated audits and Minimum Generation Emergency consistent with the reason provided by the ISO when issuing a Dispatch Instruction for the Resource. If there is more than one reason provided by the ISO when issuing the Dispatch Instruction, the NCPC Credits are divided equally for purposes of the above designations. With the exception of Day-Ahead External Transaction Import and Increment Offer NCPC Credits and Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, the hourly credits are summed to determine the total credits for each NCPC Charge category for a day.

**III.F.3. Charges for NCPC**

**III.F.3.1. Cost Allocation.**

**III.F.3.1.1 Day-Ahead Energy Market NCPC Cost Allocation.** NCPC costs for the Day-Ahead Energy Market are allocated and charged as follows:

- (a) The total NCPC cost for the Day-Ahead Energy Market associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.
- (b) The total NCPC cost for the Day-Ahead Energy Market for resources designated as Special Constraint Resources in the Day-Ahead Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.
- (c) The total NCPC cost for the Day-Ahead Energy Market for resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.
- (d) For each External Node, the total NCPC cost for Day-Ahead External Transaction Import and Increment Offer NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Load Obligations at the External Node for the hour.
- (e) For each External Node, the total Day-Ahead External Transaction Export and Decrement Bid NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Generation Obligations at the External Node for the hour.
- (f) All remaining NCPC costs for the Day-Ahead Energy Market (except the NCPC costs for Storage DARDs) are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub).
- (g) All remaining NCPC costs for the Day-Ahead Energy Market associated with Storage DARDs are allocated and charged to Market Participants based on their pro rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub) excluding Day-Ahead Load Obligations associated with Storage DARDs.

**III.F.3.1.2. Real-Time Energy Market NCPC Cost Allocation.** NCPC costs for the Real-Time Energy Market are allocated and charged as follows, subject to the conditions in Section III.F.3.1.3:

- (a) The total NCPC cost for the Real-Time Energy Market associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are allocated and charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.
- (b) The total NCPC cost for the Real-Time Energy Market for resources designated as Special Constraint Resources in the Real-Time Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.
- (c) The total ISO initiated audit NCPC cost for resources performing an ISO initiated audit is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.
- (d) The total NCPC cost for resources being Postured in the Real-Time Energy Market is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.
- (e) The total NCPC cost for Rapid Response Pricing Opportunity Cost NCPC Credit during pricing intervals in which one or more Rapid Response Pricing Asset is committed in the Real-Time Energy Market (and not Self-Scheduled) is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.
- (f) The total NCPC cost for the Real-Time Energy Market for resources identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.
- (g) Total Minimum Generation Emergency Credits within a Reliability Region are allocated and charged hourly to Market Participants based on each Market Participant's pro rata share of Real-Time Generation Obligations, and positive Real-Time Demand Reduction Obligations, excluding that portion of a Market Participant's Real-Time Generation Obligation and Real-Time Demand Reduction Obligation within a Reliability Region that is eligible for a Real-Time Dispatch NCPC Credit pursuant to Section III.F.2.2.3 during a Minimum Generation Emergency.
- (h) The total NCPC cost for Real-Time Dispatch Lost Opportunity Cost NCPC Credits is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Storage DARDs.
- (i) All remaining NCPC costs for the Real-Time Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of the absolute values of a Market Participant's (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day

(excluding certain positive Real-Time Load Obligation Deviations as described in Section III.F.3.1.3(d)); (ii) generation deviations for Pool-Scheduled Resources not following Dispatch Instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following Dispatch Instructions, and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following Dispatch Instructions, including External Resources, in MWhs during the Operating Day; (iii) demand reduction deviations for Pool-Scheduled Demand Response Resources not following Dispatch Instructions; and (iv) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day. The Real-Time deviations calculation is specified in greater detail in Section III.F.3.2.

### **III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation.**

- (a) If a Generator Asset has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.
- (b) If a Demand Response Resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the resource should not be dispatched in order to avoid a Minimum Generation Emergency, the Market Participant will be responsible for all Real-Time Demand Reduction Obligation Deviation charges, but will not incur related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.
- (c) Any difference between the actual consumption (Real-Time Load Obligation) of a DARD and the DARD's Demand Bids that clear in the Day-Ahead Energy Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation for the purpose of allocating costs for Real-Time Energy Market NCPC Credits.
- (d) In any hour during which a Capacity Scarcity Condition occurs or ISO New England Operating Procedure No. 4 or ISO New England Operating Procedure No. 7 are implemented, any NCPC Charges that would have been allocated pursuant to Section III.F.3.2 to net positive Real-Time Load Obligation Deviations in an affected Load Zone (and related portion of adjacent External Nodes) are instead allocated and charged to Market Participants based on their pro rata share of the sum of their Real-Time Load Obligation (excluding Real-Time Load Obligations associated with a Postured Dispatchable Asset Related Demand Resource) in all the affected Load Zones and (and related portion of adjacent External Nodes) during the affected hour(s). For purposes of this calculation, the

ISO shall apportion any Real-Time Load Obligations and Real-Time Load Obligation Deviations at an External Node equally among the Load Zones to which the External Node is interconnected.

### **III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits.**

Each Market Participant's pro-rata share of the Real-Time deviations for Real-Time Energy Market NCPC Credits is the following:

- (a) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

- (b) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) or (Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

- (c) For each Self-Scheduled Generator Asset (other than a Continuous Storage Generator Asset), if the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).



If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

**plus,**

(d) for each Pool-Scheduled Generator Asset and Continuous Storage Generator Asset:

- (i) If the Generator Asset is not following Dispatch Instructions, has cleared Day-Ahead, has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – Desired Dispatch Point) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

- (ii) If the Generator Asset is not following Dispatch Instructions, has cleared Day-Ahead, has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – cleared Day-Ahead MWh) for each Generator Asset.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

**plus,**

(e) for each Pool-Scheduled Demand Response Resource:

- (i) If the Demand Response Resource is being dispatched, is not following Dispatch Instructions, has cleared Day-Ahead, and has not been ordered to stop reducing demand for reliability purposes: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction – Desired Dispatch Point) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

- (ii) If the Demand Response Resource is unavailable and has cleared Day-Ahead: Real-Time demand reduction deviation is the absolute value of (Real-Time demand reduction – cleared Day-Ahead MWh) for each Demand Response Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

**plus,**

- (f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation,

where

- (i) each Market Participant's Real-Time Load Obligation Deviation for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub), and
- (ii) for purposes of calculating a Participant's Real-Time Load Obligation Deviation under this subsection (e), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and
- (iii) External Transaction sales curtailed by the ISO are omitted from this calculation.

**plus,**

- (g) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation,

where

- (i) each Market Participant's Real-Time Generation Obligation Deviation at External Nodes for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes, and

- (ii) for purposes of calculating a Participant's Real-Time Generation Obligation Deviation under this sub-section (f), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and
- (iii) External Transaction purchases curtailed by the ISO are omitted from this calculation.

**plus,**

- (h) the absolute value of the total over all Locations of the Market Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

### **III.F.3.3 Local Second Contingency Protection Resource NCPC Charges.**

Each Market Participant's pro-rata share of the cost for Day-Ahead Energy Market NCPC Credits and Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection is based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region, excluding Real-Time Load Obligations associated with Storage DARDs subject to the following conditions:

- (a) The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating a Market Participant's pro-rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.
- (b) For hours in which there is an NCPC cost for a resource providing Local Second Contingency Protection and ISO is selling Emergency Energy to an adjacent Control Area, the scheduled amount of Emergency Energy at the applicable External Node will be included in the calculation of a Market Participant's pro rata share of the cost for Real-Time Energy Market NCPC Credits for resources

designated to provide Local Second Contingency Protection as if the Emergency Energy sale were a Real-Time Load Obligation within each affected Reliability Region. The pro rata share calculated for the Emergency Energy transaction shall be included in the charges under an agreement for purchase and sale of Emergency Energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency Energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

<b>External Node Common Name</b>	<b>Associated Transmission Facilities</b>	<b>Reliability Region(s)</b>	<b>Allocator</b>
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390/3016) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-7 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line)  Alps – Berkshire Line (393Line)  Pleasant Valley – Long Mountain Line (398 Line)	Vermont, Vermont Vermont West Central Massachusetts  West Central Massachusetts  Connecticut	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
NY NNC External Node	Northport-Norwalk Harbor (601,602 and 603 Lines)	Connecticut	100% to Connecticut
NY CSC External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(c) For each month, the ISO performs an evaluation of total Local Second Contingency Protection Resource NCPC Charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph c, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency Energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Storage DARD.

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge  $_{(Reliability\ Region, month)}$   $>$   $.06 \times$  Load Weighted Real-Time LMP  $_{(Reliability\ Region, month)}$

Condition 2 – is the Local Second Contingency Protection Resource Charge %  $_{(Reliability\ Region, month)}$   $>$   $2 \times$  Twelve Month Rolling Average Local Second Contingency Protection Resource Charge %  $_{(Reliability\ Region)}$

Where:

Real-Time Load Obligation  $_{(Reliability\ Region, month)}$  equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge  $_{(Reliability\ Region, month)}$  equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation  $_{(Reliability\ Region, month)}$ .

Load Weighted Real-Time LMP  $_{(Reliability\ Region, month)}$  equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation  $_{(Reliability\ Region, month)}$ .

Local Second Contingency Protection Resource Charge % (Reliability Region, month) equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP (Reliability Region, month).

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % (Reliability Region) equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge % (Reliability Region, month) divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % (Reliability Region), a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % (Reliability Region) value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge (Reliability Region, month) is triggered.

- (ii) Determination of the portion of Local Second Contingency Protection Resource Charge (Reliability Region, month) to be reallocated –

Local Second Contingency Protection Resource Charge (Reliability Region, month) to be reallocated = Real-Time Load Obligation (Reliability Region, month) X Min (Condition 1 Rate (Reliability Region, month), Condition 2 Rate (Reliability Region, month))

Where:

Condition 1 Rate (Reliability Region, month) equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) minus .06 times the Load Weighted Real-Time LMP (Reliability Region, month).

Condition 2 Rate (Reliability Region, month) equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % (Reliability Region) times the Load Weighted Real-Time LMP (Reliability Region, month).

- (iii) Determination of Local Second Contingency Protection Resource Charge (Reliability Region, month) reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

$$\left( \text{Real-Time Load Obligation}_{(\text{Participant, Reliability Region, month})} / \text{Real-Time Load Obligation}_{(\text{Reliability Region, month})} \right) * \text{Local Second Contingency Protection Resource Charges}_{(\text{Reliability Region, month})}$$
 to be reallocated

Where:

Real-Time Load Obligation<sub>(Participant, Reliability Region, month)</sub> equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

$$\left( \text{Regional Network Load}_{(\text{Transmission Customer, Reliability Region, month})} / \text{Regional Network Load}_{(\text{Reliability Region, month})} \right) * \text{Local Second Contingency Protection Resource Charges}_{(\text{Reliability Region, month})}$$
 to be reallocated

Where:

Regional Network Load<sub>(Reliability Region, month)</sub> equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load<sub>(Customer, Reliability Region, month)</sub> equals:

The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

#### **III.F.4. NCPC Reporting**

**III.F.4.1. Zonal NCPC Report.** Beginning January 2019, for each month, no later than 20 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible

portion of its website, a report indicating the aggregate dollar amount of NCPC Credits by category paid to the resources located in each Load Zone for each day during that month.

**III.F.4.2. Resource-Specific NCPC Report.** Beginning January 2019, for each month, no later than 90 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating the name of each resource that received NCPC Credits for that month and the total dollar amount of NCPC Credits that each of those resources received for that month.

**III.F.4.3. Operator-Initiated Commitment Report.** Beginning January 2019, for each month, no later than 30 days after the end of the month, the ISO shall post, in a machine-readable format on a publicly accessible portion of its website, a report indicating each resource commitment made during that month after the Day-Ahead Energy Market for a reason other than minimizing the total production costs of serving load. For each such commitment, the report shall include the start time, the Economic Maximum Limit or Maximum Reduction of the committed resource, the Load Zone in which the committed resource is located, and the reason for the commitment.



1 UNITED STATES OF AMERICA  
2 BEFORE THE  
3 FEDERAL ENERGY REGULATORY COMMISSION  
4

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6  
7 ISO New England Inc. and  
8 New England Power Pool

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Docket No. ER19-\_\_\_\_-000

9  
10 TESTIMONY OF BENJAMIN EWING  
11

12 **Q: PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.**

13 A: My name is Benjamin Ewing. I am employed by ISO New England Inc. (the  
14 “ISO”), where I am a Lead Analyst in the Market Development Department. My  
15 business address is One Sullivan Road, Holyoke, Massachusetts 01040.<sup>1</sup>  
16

17 **Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND**  
18 **RELEVANT PROFESSIONAL EXPERIENCE.**

19 A: I have been with the ISO since May 2009 and have held analytical positions  
20 within the Market Analysis and Settlements and Market Development  
21 departments during this time. In my current role, I am responsible for identifying  
22 and developing market design improvements for New England’s competitive  
23 wholesale electricity markets and presenting these market improvements to  
24 external stakeholders. I have provided testimony to the Federal Energy  
25 Regulatory Commission (the “Commission”) in support of other ISO market rule

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<sup>1</sup> Capitalized terms used but not defined in this testimony are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff (the “Tariff”), the Second Restated New England Power Pool Agreement, and the Participants Agreement. Market Rule 1 is Section III of the Tariff.

1 changes, including revisions to the energy market offer cap treatment of so-called  
2 “fast start” resources (Docket No. ER17-1542-000), changes to natural gas price  
3 indices used in determining various strike and threshold prices in ISO markets  
4 (Docket No. ER17-337-000), and assorted changes to Net Commitment Period  
5 Compensation credit calculations (Docket No. ER17-2569-000). I hold a B.A. in  
6 Applied Mathematics from Washington University in St. Louis, and an M.S. in  
7 Industrial Engineering and Operations Research from the University of  
8 Massachusetts.

9

10 **I. INTRODUCTION AND OVERVIEW**

11 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

12 A: The purpose of my testimony is to explain the rationale for a proposed revision to  
13 the dispatch treatment of resources whose Supply Offers are price-capped in the  
14 Day-Ahead Energy Market.

15

16 **Q: WHY IS THE ISO PROPOSING THIS CHANGE AT THIS TIME?**

17 A: In May 2017, the ISO and the New England Power Pool filed Tariff revisions to  
18 comply with the Commission’s Order No. 831 energy market offer cap  
19 requirements (the “Order 831 Offer Cap Revisions”).<sup>2</sup> To comply with the Order  
20 No. 831 offer cap requirements, the ISO modified its market rules to add a new  
21 Tariff provision that addresses the offer capping and cost verification

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<sup>2</sup> See *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,115 (2016) (“Order No. 831”); *ISO New England Inc. and New England Power Pool*, Market Rule 1 Revisions to Modify Energy Market Offer Caps in Compliance with Order No. 831, Docket No. ER17-1565-000 (filed May 8, 2017) (the “Order 831 Compliance Filing”).

1 requirements for all energy market offers with incremental energy costs above  
2 \$1,000/MWh. To implement the \$2,000/MWh cap required under Order No. 831  
3 for price calculation purposes, the Order 831 Offer Cap Revisions specify that if  
4 the incremental energy portion of the offer is above \$2,000/MWh, then it is  
5 capped at \$2,000/MWh for purposes of performing the day-ahead market and  
6 real-time market pricing calculations. The Commission accepted the Order 831  
7 Offer Cap Revisions by order dated November 9, 2017.<sup>3</sup>

8  
9 After further evaluation, the ISO is proposing to change one aspect of the way the  
10 \$2,000/MWh offer cap functions in the Day-Ahead Energy Market clearing.

11

## 12 **II. EXPLANATION OF THE PROPOSED REVISION**

13 **Q: PLEASE EXPLAIN HOW THE \$2,000/MWH OFFER CAP FUNCTIONS**  
14 **UNDER THE ORDER 831 OFFER CAP REVISIONS.**

15 A: The Order 831 Offer Cap Revisions apply the \$2,000/MWh cap to cost-verified  
16 incremental energy offers only for purposes of pricing. The revisions specifically  
17 do not cap cost-verified incremental energy offers for commitment or dispatch  
18 purposes. Therefore, under the rules as accepted by the Commission, cost-  
19 verified incremental energy offers above \$2,000/MWh are to be used in  
20 determining economic merit-order commitment *and* dispatch decisions in both the

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<sup>3</sup> Letter Order Accepting Tariff Revision to Modify Energy Market Offer Caps in Compliance with Order No. 831, Docket No. ER17-1565-000 (issued November 9, 2017).

1 Day-Ahead Energy Market and the Real-Time Energy Market, even though for  
2 pricing purposes the offers are capped at \$2,000/MWh.

3

4

5 **Q: WAS THIS TREATMENT REQUIRED UNDER ORDER NO. 831?**

6 A: No. While Order No. 831 capped incremental energy offers at \$2,000/MWh for  
7 price calculations, Order No. 831 also stated that for cost-based incremental  
8 energy offers above \$2,000/MWh, “we expect RTOs/ISOs to use such offers to  
9 determine merit-order dispatch.”<sup>4</sup> The Commission subsequently clarified that  
10 Order No. 831 did not *require* the use of cost-based incremental energy offers  
11 above \$2,000/MWh in determining merit-order dispatch, but rather the  
12 Commission was only encouraging such treatment to the extent possible.<sup>5</sup>

13

14 **Q: PLEASE EXPLAIN THE PROPOSED CHANGE.**

15 A: As the ISO has worked through the implementation of the Order 831 Offer Cap  
16 Revisions, it has determined that using cost-verified incremental energy offers  
17 above \$2,000/MWh in the dispatch software in the Day-Ahead Energy Market is  
18 significantly more complex than it originally anticipated and would result in a

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<sup>4</sup> Order No. 831 at P 42.

<sup>5</sup> *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order on Rehearing and Clarification*, 161 FERC ¶ 61,156 (2017) at P 16 (“[W]e clarify that Order No. 831 did not require cost-based incremental energy offers above \$2,000/MWh to be used to determine economic merit-order dispatch. We recognize that some RTO’s/ISO’s existing commitment, dispatch, and pricing algorithms are structured differently, and the Commission in Order No. 831 did not require RTOs/ISOs to change their current practices or software to use cost-based incremental energy offers above \$2,000/MWh for determining economic merit-order dispatch. However, in the event that RTOs/ISOs must select from several offers above \$2,000/MWh, we encourage RTOs/ISOs to make those selections on a least-cost basis when possible, in order to minimize the cost to serve load.”).

1 further delay in the implementation of the Order 831 Offer Cap Revisions. Rather  
2 than delay the implementation further—and because the Commission expressly  
3 has not required the use of cost-verified offers above \$2,000/MWh for dispatch  
4 purposes—the ISO is now amending its Order 831 Offer Cap Revisions to clarify  
5 that verified offers greater than \$2,000/MWh will be capped at \$2,000/MWh for  
6 use in determining the Day-Ahead Energy Market dispatch quantities, as well as  
7 for Day-Ahead price calculations.

8

9 **Q: HOW DOES THIS PROPOSED CHANGE IMPACT THE DISPATCH OF**  
10 **RESOURCES WITH OFFERS THAT ARE CAPPED AT \$2,000/MWH?**

11 A: The proposed change states that for purposes of scheduling a resource in the Day-  
12 Ahead Energy Market once the initial commitment decision is made, the  
13 incremental energy offer value will be capped at \$2,000/MWh. In the Day-Ahead  
14 Energy Market the term “scheduling” refers to both the initial commitment  
15 decision and the determination of what MWh level the resource will be dispatched  
16 *to once the decision to commit the resource is made*. Under the proposed change,  
17 cost-verified offers above \$2,000/MWh *will* be used in determining which  
18 resources to *commit and bring online* in the Day-Ahead Energy Market clearing  
19 process—meaning, in other words, that no change is being proposed to the offer  
20 cap rules with respect to the initial commitment decision. However, once the  
21 commitment decision is made, offers will be capped at \$2,000/MWh for purposes  
22 of determining the level to which the resource will be dispatched.

23

1 **Q: CAN YOU PROVIDE AN EXAMPLE OF HOW THE OFFER CAP WILL**  
2 **WORK IN THE DAY-AHEAD ENERGY MARKET UNDER THE**  
3 **PROPOSED REVISION?**

4 A: Yes. Suppose Resources A, B, and C are being evaluated for clearing in the Day-  
5 Ahead Energy Market. These resources offer a single price for their full  
6 capability, and are identical except for their verified offer price.

	Economic Minimum Limit (MW)	Economic Maximum Limit (MW)	Verified Offer Price (\$/MWh)
Resource A	10	20	\$2,100
Resource B	10	20	\$2,200
Resource C	10	20	\$2,300

7  
8 Suppose that 15 MWh of demand remains to be satisfied in the Day-Ahead  
9 Energy Market, and these three resources are the only ones remaining in the  
10 supply stack. The Day-Ahead commitment process will consider the uncapped,  
11 verified offer of each resource when deciding how to meet demand. As a result, it  
12 will choose to commit the less expensive Resource A and leave the more  
13 expensive Resources B and C offline. This is an efficient outcome.

14  
15 Now, suppose instead that 30 MWh of demand remain to be satisfied. The Day-  
16 Ahead *commitment* process would commit Resources A and B, again selecting the  
17 lowest cost resources available to satisfy demand. The Day-Ahead *dispatch* and  
18 *pricing* process, however, would treat each of these committed resources as a  
19 \$2,000/MWh resource by application of the hard cap of \$2,000/MWh. As a result

1 of the application of this cap to dispatch as well as to pricing, Resources A and B  
2 would be dispatched pro-rata at 15 MW each.

3

4 **Q: WHY IS THE ISO CHANGING THE OFFER CAP TREATMENT IN THE**  
5 **DAY-AHEAD ENERGY MARKET RATHER THAN SIMPLY DELAYING**  
6 **THE IMPLEMENTATION OF THE CURRENTLY-FILED RULES?**

7 A: The ISO evaluated whether to simply delay the implementation of this aspect of  
8 the Order 831 Offer Cap Revisions, rather than remove it altogether, and decided  
9 against delay for two reasons. First, the amount of work to create this additional  
10 functionality in the Day-Ahead Energy Market clearing is significant. The  
11 functionality was developed for the Real-Time Energy Market as part of the ISO's  
12 fast start pricing initiative. The software changes for the fast start pricing  
13 initiative were some of the more complex changes undertaken by the ISO since  
14 the implementation of the current market rules. Much of this same work would  
15 need to be performed to "separate" pricing from dispatch in the Day-Ahead  
16 Energy Market. Given that New England has not experienced input fuel prices  
17 that would warrant offers close to the \$2,000/MWh offer cap, the ISO cannot  
18 justify the expenditure in time or energy that would be required to accomplish this  
19 narrow objective at this time.

20

21 Furthermore, a market clearing software re-platforming is currently being  
22 evaluated by both ISO New England and several other ISO/RTOs. While a  
23 timeline has not yet been completed for this project, with this re-platforming the

1 future version of the Day-Ahead Energy Market software will inherently include  
2 separate dispatch and pricing processes in a manner that will likely allow  
3 scheduling to fully utilize uncapped offers.

4

5 In short, implementing this change now to the existing Day-Ahead Energy Market  
6 process would require substantial effort to implement a short-lived change that is  
7 unlikely to provide significant value to the marketplace.

8

9 **Q: CAN YOU ELABORATE ON THE CHALLENGES THE ISO WOULD**  
10 **FACE IN IMPLEMENTING THE DAY-AHEAD OFFER CAP**  
11 **REQUIREMENTS AS CURRENTLY FILED?**

12 A: To implement the Day-Ahead offer cap as originally envisioned (i.e., with the  
13 dispatch using the verified cost-based offers above \$2,000/MWh) would require  
14 separating the dispatch process from the pricing process in the Day-Ahead Energy  
15 Market clearing software, so that capped offers could be used for pricing purposes  
16 whereas the verified cost-based offers could be used for dispatch purposes.  
17 Currently, the Day-Ahead Energy Market software comprises two separate  
18 clearing engines. The “Resource Scheduling and Commitment” engine, or  
19 “RSC,” first determines the multi-interval commitment. The “Schedule, Pricing  
20 and Dispatch” engine, or “SPD,” then uses the commitment from the RSC and  
21 determines dispatch quantities (at or above the resource’s Economic Minimum  
22 Limit) for each resource and interval, as well as Day-Ahead Locational Marginal  
23 Prices. To implement the day-ahead offer cap rules as originally envisioned



1 would require splitting SPD’s single optimization into two distinct  
2 optimizations—a pricing run and a dispatch run. To complete this work for the  
3 Real-Time Energy Market as part of the fast-start pricing changes took the ISO  
4 approximately 17 months and cost approximately \$4.9 million. Incorporating  
5 these changes into the Day-Ahead Energy Market would be comparable in cost  
6 and in time, and would present a number of challenges:

- 7 • Separating the pricing and dispatch processes would require an additional  
8 optimization as part of clearing the Day-Ahead Energy Market, which could  
9 require additional processing time and would raise performance  
10 considerations.
- 11 • Separating the pricing and dispatch processes would have downstream  
12 impacts on the market system database structures, the interfaces used to  
13 retrieve and store data, and the software tools used for analysis.
- 14 • Market clearing engines are critical to ISO operations, and modifications to  
15 these engines introduce risk. Therefore, extensive internal regression testing  
16 and external certification would be required as a result of this change, both of  
17 which are time-intensive processes.

18 Again, given the plans by multiple ISOs/RTOs to overhaul the market clearing  
19 platform, and given the limited risk to market outcomes that the proposed  
20 modified treatment of the offer caps has, the ISO believes it is not prudent to take  
21 on the significant work that would be required to implement the Day-Ahead offer  
22 caps as originally envisioned.

23

1 **Q: CAN YOU ELABORATE ON WHY THE PROPOSED MODIFIED**  
2 **TREATMENT OF THE OFFER CAPS IN THE DAY-AHEAD MARKET IS**  
3 **NOT LIKELY TO HAVE AN ADVERSE IMPACT ON MARKET**  
4 **OUTCOMES?**

5 A: A key objective of the Order No. 831 offer cap requirements is to allow the  
6 marginal costs associated with volatile natural gas prices to be properly reflected  
7 in market clearing prices. *See* Order No. 831 at P 90 (discussing high natural gas  
8 prices during the Polar Vortex in the context of establishing the \$2,000/MWh  
9 cap). In the last 10 years the highest observed Day-Ahead gas price in New  
10 England has been \$107/MMBtu, which is well below a price that would justify a  
11 Day-Ahead offer greater than \$2,000/MWh at any heat rate in New England's  
12 gas-fired generator fleet. Therefore, the dispatch of resources in the Day-Ahead  
13 Energy Market is unlikely to be impacted by the proposal to cap Day-Ahead  
14 offers at \$2,000/MWh for dispatch purposes.

15  
16 **Q: DOES THIS CONCLUDE YOUR TESTIMONY?**

17 A: Yes, this concludes my testimony.

18

19 I declare that the foregoing is true and correct.

20 Executed on June 13, 2019.

21

22

23

24

  
Benjamin Ewing

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