SECTION III

MARKET RULE 1

STANDARD MARKET DESIGN

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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:

Duration Required for an Establish Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
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:

Duration Required for a Seasonal Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
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) Hydraulic Turbine-Other	2
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:

Duration Required for an ISO-Initiated Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
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
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 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, which is an audit that measures a Reactive Resource's ability to provide reactive power to the transmission system at a specified real power output or consumption.

(ii) A leading Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to absorb reactive power from the transmission system at a specified real power output or consumption.

(b) The ISO shall develop a list of Reactive Resources that must conduct Reactive Capability Audits. The list shall include Reactive Resources that: (i) have a gross individual nameplate rating greater than 20 MVA; (ii) are directly connected, or are connected through equipment designed primarily for delivering real or reactive power to an interconnection point, to the transmission system at a voltage of 100 kV or above; and (iii) are not exempted from providing voltage control by the ISO. Additional criteria to be used in adding a Reactive Resource to the list includes, but is not limited to, the effect of the Reactive Resource on System Operating Limits, Interconnection Reliability Operating Limits, and local area voltage limits during the following operating states: normal, emergency, and system restoration.

(c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall 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 Reactive Resource shall reflect any limitations based upon the interdependence of common elements between two or more Reactive Resources 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 shall be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Reactive Resource to conduct Reactive Capability Audits more often than every five years if:

(i) there is a change in the Reactive Resource that may affect the reactive power capability of the Reactive Resource;

(ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Reactive Resource; or

(iii) historical data shows that the amount of reactive power that the Reactive Resource can provide to or absorb from the transmission system is higher or lower than the latest audit data.

(h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may 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. The ISO shall use a joint optimization process to serve Day-Ahead Market energy requirements and Day-Ahead Ancillary Services requirements, as described in Section III.1.10.8(a).

(b) [Reserved].

(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 LMP-Based 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.1.7.9A Day-Ahead Ancillary Services Prices.

The prices paid by the ISO for the provision of Day-Ahead Ancillary Services in the New England Markets will reflect Day-Ahead Ancillary Services clearing prices determined by the ISO in accordance with the ISO New England Filed Documents.

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 potential referral under Section III.A.19.

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 Day-Ahead Ancillary Services and Forecast Energy Requirement.

III.1.8.1 Day-Ahead Ancillary Services Offers.

Market Participants may submit Day-Ahead Ancillary Services Offers for the Operating Day in the Day-Ahead Ancillary Services Market as specified in this Section III.1.8.1.

(a) Each Day-Ahead Ancillary Services Offer shall be associated with a specific Generator Asset, Demand Response Resource, or DARD for which the Market Participant has submitted a corresponding Supply Offer, Demand Reduction Offer, or Demand Bid in the Day-Ahead Energy Market for the same hour of the Operating Day.

(b) Each Day-Ahead Ancillary Services Offer shall specify: (i) the hour of the Operating Day for which the Day-Ahead Ancillary Services Offer applies; (ii) product-specific offer prices, in $/MWh, that are greater than or equal to zero for the Day-Ahead Ancillary Services; and (iii) a single offer quantity, in MWh, that is greater than or equal to zero. The offer prices for the Day-Ahead Ancillary Services shall not exceed the Forecast Energy Requirement Penalty Factor as specified in Section III.2.6.2(d) of this Market Rule 1. The offer quantity shall not exceed the Economic Maximum Limit specified in the associated Supply Offer, the Maximum Reduction specified in the associated Demand Reduction Offer, or the Maximum Consumption Limit specified in the associated Demand Bid.

(c) As part of its Day-Ahead Ancillary Services Offer, a Market Participant is permitted to specify a Maximum Daily Award Limit quantity, in MWh, that is greater than or equal to zero.

(d) For each hour of the Operating Day, a Market Participant may submit only one Day-Ahead Ancillary Services Offer associated with a specific Generator Asset, Demand Response Resource, or DARD.

(e) Day-Ahead Ancillary Services Offers shall be submitted by the offer submission deadline for the Day-Ahead Market specified in Section III.1.10.1A of this Market Rule 1. A Day-Ahead Ancillary Services Offer shall not remain in effect for subsequent Operating Days.

III.1.8.2 Day-Ahead Ancillary Services Strike Price.

(a) For each hour of the Operating Day, the ISO shall specify the Day-Ahead Ancillary Services Strike Price in $/MWh. The value of the Day-Ahead Ancillary Services Strike Price represents an amount that is the greater of (i) $10/MWh greater than a forecast of the expected hourly Real-Time Hub Price for such hour of the Operating Day and (ii) zero.

(b) The forecast used to determine the Day-Ahead Ancillary Services Strike Price shall be based on a publicly-available forecasting algorithm developed by the ISO. The ISO shall describe the publicly-available forecasting algorithm to Market Participants and shall periodically review and assess the efficacy of the forecasting algorithm. The ISO shall notify stakeholders of any potential revisions to the ISO's forecasting algorithm prior to implementing such revisions.

(c) In the event that the ISO is not able to utilize the ISO-developed forecasting algorithm described in subsection (b) above due to hardware, software, or telecommunications problems, human error, or exigent circumstances not contemplated by this market rule, the ISO shall determine the Day-Ahead Ancillary Services Strike Price using the best forecast available and shall disclose the use of such substitute forecast to Market Participants as soon as practicable.

III.1.8.3 Day-Ahead Flexible Response Services Demand Quantities.

The Day-Ahead Ancillary Services Market shall endeavor to procure the Day-Ahead Flexible Response Services Demand Quantities specified in this Section III.1.8.3.

(a) For each hour of the Operating Day, the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the Ten-Minute Spinning Reserve Requirement projected Day-Ahead.

(b) For each hour of the Operating Day, the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the Ten-Minute Reserve Requirement projected Day-Ahead.

(c) For each hour of the Operating Day, the Day-Ahead Minimum Total Reserve Demand Quantity shall be equal to the Minimum Total Reserve Requirement projected Day-Ahead.

(d) For each hour of the Operating Day, the Day-Ahead Total Reserve Demand Quantity shall be equal to the Total Reserve Requirement projected Day-Ahead.

III.1.8.4 Forecast Energy Requirement Demand Quantity.

For each hour of the Operating Day, the Forecast Energy Requirement Demand Quantity shall be equal to the ISO forecast for the total load in the New England Control Area produced pursuant to Section III.1.10.1A(h) of this Market Rule 1.

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 and Demand Reduction 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 the Day-Ahead Market and a Real-Time Energy Market.

(b) The Day-Ahead Market shall enable Market Participants to purchase and sell energy and sell ancillary services 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 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 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 and Day-Ahead Ancillary Services Market Scheduling.

Market Participants may submit offers and bids in the Day-Ahead Market until 10:30 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 applicable 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. 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) In the Day-Ahead Energy Market, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) In the Day-Ahead Energy Market, the offer prices for all Self-Scheduled 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 may submit Supply Offers for the supply of energy for the following Operating Day.

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 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 <u>(excluding Coordinated External Transactions)</u> 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^{th} 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 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.

(l) **Day-Ahead Ancillary Services Offers** – Market Participants selling into the New England Markets from Generator Assets or Demand Response Resources or participating in the New England Markets with DARDs, and that have submitted Supply Offers, Demand Reduction Offers, or Demand Bids for the following Operating Day, as described in subsections (c), (d), and (e) of this Section III.1.10.1A, may submit Day-Ahead Ancillary Services Offers for the following Operating Day. Day-Ahead Ancillary Services Offers shall be submitted to the ISO in accordance with Section III.1.8.1 of this Market Rule 1.

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, ancillary services, 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 and ancillary services 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 Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids, ancillary services offers and requirements, and the Forecast Energy Requirement Demand Quantity.

(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.

Market Participants with External Resources may submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

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 and storing the energy for later injection of electricity into 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 directly metered;

(iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;

(v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;

(vi) settle its injection of electricity to the grid as a Generator Asset and any receipt of electricity from the grid as a DARD;

(vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and

(viii) 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 storage facility incapable of receiving and storing electricity from the grid may participate in the New England Markets as a Continuous Storage Facility, so long as that facility satisfies all Continuous Storage Facility registration and participation requirements that are not solely related to consumption capability. Notwithstanding Section III.1.10.6(a), Section III.1.10.6(c), and any other related provisions, such non-consuming storage facilities shall not be required to:

(i) be capable of consuming at least 0.1 MW from the grid; or

(ii) be capable of modifying consumption responsive to Dispatch Instructions.

(e) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:

(i) A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.

(ii) A storage facility's charging energy shall not qualify as, or be billed to, a Storage DARD if that facility's charging energy is included in another Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging energy.

(iii) The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.

(iv) Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.

(v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.

(f) 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.

(g) 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.

(h) 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.)

(i) 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.

(j) 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 procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.

(d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID 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 Transaction Scheduling.

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 e-Tag ID 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 the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, permit the transaction to be scheduled.

III.1.10.8 Scheduling Considerations.

(a) In scheduling the Day-Ahead Market, the ISO shall use its best efforts to determine the security-constrained economic commitment and dispatch that jointly optimizes: (i) Demand Bids, Decrement Bids, Demand Reduction Offers, Supply Offers, Increment Offers, and External Transactions, for energy; (ii) Day-Ahead Ancillary Services Offers to satisfy the Day-Ahead Flexible Response Services Demand Quantities; and (iii) Supply Offers, Demand Reduction Offers, External Transactions, and Day-Ahead Ancillary Services Offers to satisfy the Forecast Energy Requirement Demand Quantity.

In making the determination specified in this subsection (a), the ISO shall take into account, as applicable: (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 ancillary services; (vi) the operational capabilities of any Resource to adjust the output, consumption, or demand reduction within the operating characteristics and parameters specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, or Demand Bid and any audited values of such operating characteristics and parameters; (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.

In scheduling the Day-Ahead Market, the following limitations shall apply:

(i) For purposes of satisfying the Day-Ahead Flexible Response Services Demand Quantities specified in Sections III.1.8.3(a) through (d), the ISO shall not take into account a Day-Ahead Ancillary Services Offer unless the Generator Asset, Demand Response Resource, or DARD associated with the Day-Ahead Ancillary Services Offer meets the eligibility requirements enumerated in Section III.1.7.19.1.

(ii) For purposes of satisfying the Forecast Energy Requirement Demand Quantity specified in Section III.1.8.4, the ISO shall not take into account a Day-Ahead Ancillary Services Offer unless the offer is associated with a Generator Asset or Demand Response Resource that meets the following conditions:

(1) The Generator Asset or Demand Response Resource is, for the applicable hour, either scheduled for energy in the Day-Ahead Energy Market or is a Fast Start Generator or Fast Start Demand Response Resource.

(2) The Generator Asset or Demand Response Resource is not designated as constrained by transmission limitations, as described in Section III.1.7.19.1(3).

(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 and ancillary services 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 Market cannot 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. The ISO shall use its best efforts to determine the least-cost means to satisfy any remaining reliability requirements of the New England Control Area for the Operating Day.

(d) Market Participants shall pay and be paid for the quantities of energy and ancillary services scheduled in the Day-Ahead Market based upon applicable 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 the price of 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 request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. 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(b) 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, and nuclear-powered 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, solar, 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 Market Participant may elect, but is not required, to have a wind, solar, 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.

(ii) 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.

(c) Wind and solar Generator Assets that are not Settlement Only Resources shall electronically transmit meteorological and forced outage data, as specified below, to the ISO, over a secure network, using the protocol specified in the ISO Operating Documents, for the development and deployment of wind and solar power production forecasts.

Wind Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

(i) at least once every 30 seconds: wind speed, and wind direction;

(ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, and standard deviation of ambient air relative humidity;

(iii) at least once every 5 minutes: Real-Time High Operating Limit, Wind High Limit, wind turbine counts; and

(iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Wind Plant Future Availability.

Solar Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

(i) at least once every 30 seconds: irradiance;

(ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, standard deviation of ambient air relative humidity, wind speed, and wind direction;

(iii) at least once every 5 minutes: Real-Time High Operating Limit, and Solar High Limit; and

(iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Solar Plant Future Availability.

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.2 Day-Ahead Prices, Real-Time Prices, 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. Day-Ahead Ancillary Services prices and the Forecast Energy Requirement Price shall be calculated for each hour of the Operating Day, as specified in Section III.2.6.2, as part of the joint optimization of energy and ancillary services in the Day-Ahead Market.

III.2.2 General.

The ISO shall determine the least cost security-constrained economic 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, Day-Ahead Ancillary Services prices, and the Forecast Energy Requirement Price will be calculated based on the joint optimization process described in Section III.1.10.8(a) utilizing the prices of offers and bids, the Forecast Energy Requirement Penalty Factor as specified in Section III.2.6.2(d) when applicable, and Reserve Constraint Penalty Factors as specified in Section III.2.6.2(c) when applicable. 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 as specified in Section III.2.7A 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, Real-Time Reserve Clearing Prices, Day-Ahead Ancillary Services prices, and the Forecast Energy Requirement Price. 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 Day-Ahead Prices.

III.2.6.1 Calculation of Day-Ahead Locational Marginal Prices.

(a) Day-Ahead Locational Marginal Prices shall be determined on the basis of the Day-Ahead Market security-constrained economic commitment and dispatch described in Section III.1.10.8(a) and in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market. Such prices 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 Market by applying a joint optimization method consistent with Section III.1.10.8(a), 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, energy bid, or Day-Ahead Ancillary Services Offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource and the effect on ancillary service costs associated with increasing the output of the Resource or reducing consumption of 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 cost of serving an increment of load at a Node or External Node, calculated in this manner, shall determine the Day-Ahead Locational Marginal 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 all Day-Ahead fixed Demand Bids 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) 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

(ii) If power balance is not achieved after step (i), 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 (i), whichever is higher.

(c) System-level excess energy conditions. If the total cleared energy supply in the Day-Ahead Energy Market exceeds the total bid-in demand, then the following steps shall be performed to achieve energy balance:

(i) The Day-Ahead security-constrained economic dispatch process will be performed such that all committed Generator Assets shall be dispatched no lower than their respective Emergency Minimum Limits and each such Generator Asset will be treated as offering its output below its Economic Minimum Limit at the Energy Offer Floor; and

(ii) If power balance is not achieved in step (i), the Day-Ahead security-constrained economic dispatch process will be performed such that (a) all committed Generator Assets shall be dispatched no lower than zero, each such Generator Asset will be treated as having an unlimited downward ramp rate, and each such Generator Asset will be treated as offering its output below its Economic Minimum Limit at the Energy Offer Floor; and (b) all committed Demand Response Resources shall be dispatched no lower than zero, each such Demand Response Resource will be treated as having an unlimited downward ramp rate, and each such Demand Response Resource will be treated as offering its demand reduction below its Minimum Reduction at the Energy Offer Floor.

(d) Local excess energy conditions. If a transmission limit is violated in the Day-Ahead Energy Market, the following steps shall be performed:

(i) The Day-Ahead security-constrained economic dispatch process will be performed such that all Generator Assets contributing to the transmission limit violation shall be dispatched no lower than their respective Emergency Minimum Limits, and each such Generator Asset will be treated as offering its output below its Economic Minimum Limit at the Energy Offer Floor; and

(ii) If the transmission limit violation is not resolved in step (i), the Day-Ahead security-constrained economic dispatch process will be performed such that (a) all Generator Assets contributing to the transmission limit violation shall be dispatched no lower than zero, each such Generator Asset will be treated as having an unlimited downward ramp rate, and each such Generator Asset will be treated as offering its output below its Economic Minimum Limit at the

Energy Offer Floor; and (b) all Demand Response Resources contributing to the transmission limit violation shall be dispatched no lower than zero, each such Demand Response Resource will be treated as having an unlimited downward ramp rate, and each such Demand Response Resource will be treated as offering its demand reduction below its Minimum Reduction at the Energy Offer Floor.

III.2.6.2 Calculation of Additional Day-Ahead Prices.

The ISO shall calculate hourly Day-Ahead Prices for additional requirements in the Day-Ahead Market as described in this Section III.2.6.2.

(a) **Day-Ahead Flexible Response Services Clearing Prices.**

(i) The clearing price for Day-Ahead Thirty-Minute Operating Reserve shall be the incremental cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy:

(1) the next increment of Day-Ahead Minimum Total Reserve Quantity, if the cost of such next increment is greater than or equal to the Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Reserve Demand Quantity; or,

(2) if Section III.2.6.2(a)(i)(1) is inapplicable, the next increment of Day-Ahead Total Reserve Demand Quantity.

(ii) The clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve shall be the sum of (1) the incremental cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and (2) the clearing price for Day-Ahead Thirty-Minute Operating Reserve.

(iii) The clearing price for Day-Ahead Ten-Minute Spinning Reserve shall be the sum of (1) the incremental cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy the next increment of Day-Ahead Ten-Minute Spinning Reserve, and (2) the clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve.

(iv) If the Day-Ahead Market does not clear sufficient Day-Ahead Flexible Response Services to satisfy one or more of the Day-Ahead Flexible Response Services Demand Quantities, the Day-Ahead Flexible Response Services clearing prices shall be set based upon the applicable Reserve Constraint Penalty Factors, as described by Section III.2.6.2(c)(i) through (iv).

(b) **Forecast Energy Requirement Price**.

(i) The Forecast Energy Requirement Price shall be the marginal cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy the next increment of the Forecast Energy Requirement Demand Quantity.

(ii) The Forecast Energy Requirement Price shall be based upon the Forecast Energy Requirement Penalty Factor specified by Section III.2.6.2(d) when any one or some combination of the following occurs:

(1) The Day-Ahead Market does not clear sufficient energy and Day-Ahead Energy Imbalance Reserve to satisfy the Forecast Energy Requirement Demand Quantity.

(2) The Day-Ahead Locational Marginal Prices are set pursuant to Section III.2.6.1(b).

(c) **Reserve Constraint Penalty Factors in the Day-Ahead Market**. The Day-Ahead Market scheduling pursuant to Section III.1.10.8(a), and the Day-Ahead Prices specified in Section III.2.6, shall respect the applicable Reserve Constraint Penalty Factors specified below:

(i) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the Real-Time Ten-Minute Spinning Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(ii) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the Real-Time Ten-Minute Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(iii) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Minimum Total Reserve Demand Quantity shall be equal to the Real-Time Minimum Total Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(iv) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Reserve Demand Quantity shall be equal to the Real-Time Total Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(d) **Forecast Energy Requirement Penalty Factor**. The Day-Ahead Market scheduling pursuant to Section III.1.10.8(a), and the Day-Ahead Prices specified in Section III.2.6, shall respect the Forecast Energy Requirement Penalty Factor applicable to the Forecast Energy Requirement Demand Quantity. The Forecast Energy Requirement Penalty Factor shall be set at $2,575/MWh.

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 in Real-Time 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:

Real-Time Requirement	**Reserve Constraint Penalty Factor**
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

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 Market Results

(a) Day-Ahead 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 Market results for an Operating Day or if no Day-Ahead 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 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 Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead 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 Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead 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 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 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.

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area.

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.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market and Day-Ahead Ancillary Services Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for the Real-Time Energy Market is five minutes and the settlement interval for the Day-Ahead Energy Market and Day-Ahead Ancillary Services Market is hourly. The Real-Time Energy Market settlement is determined using the Metered Quantity For Settlement calculated in accordance with Section III.3.2.1.1.

(a)(1) **<u>Day-Ahead Energy Market Obligations</u>** – For each Market Participant for each settlement interval, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows:

> (i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.
>
> (ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.

(iii) **Day-Ahead Demand Reduction Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Demand Reduction Obligation at each Location equal to the MWhs of its Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market at that Location, increased by average avoided peak distribution losses. Day-Ahead Demand Reduction Obligations shall have a positive value.

(iv) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.

(v) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation plus the Day-Ahead Demand Reduction Obligation at that Location.

(a)(2) **<u>Day-Ahead Ancillary Services Market Obligations</u>** – Each Market Participant with a Day-Ahead Ancillary Services Offer that is accepted by the ISO in the Day-Ahead Ancillary Services Market shall have for each settlement interval a Day-Ahead Ancillary Services obligation. Any Day-Ahead Ancillary Services obligation related to a Demand Response Resource shall be increased by average avoided peak distribution losses.

(i) **Day-Ahead Ten-Minute Spinning Reserve Obligation** – A Market Participant with an accepted Day-Ahead Ancillary Services Offer quantity that contributes to satisfying the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall receive a Day-Ahead Ten-Minute Spinning Reserve Obligation.

(ii) **Day-Ahead Ten-Minute Non-Spinning Reserve Obligation** – A Market Participant with an accepted Day-Ahead Ancillary Services Offer quantity that contributes to satisfying the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and that same Day-Ahead Ancillary Services Offer quantity does not receive a Day-Ahead Ten-Minute Spinning Reserve Obligation, shall receive a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation.

(iii) **Day-Ahead Thirty-Minute Operating Reserve Obligation** – A Market Participant with an accepted Day-Ahead Ancillary Services Offer quantity that contributes to satisfying the Day-Ahead Total Reserve Demand Quantity, and that same Day-Ahead Ancillary Services Offer quantity does not receive either a Day-Ahead Ten-Minute Spinning Reserve Obligation or a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, shall receive a Day-Ahead Thirty-Minute Operating Reserve Obligation.

(iv) **Day-Ahead Energy Imbalance Reserve Obligation** – A Market Participant with an accepted Day-Ahead Ancillary Services Offer quantity that contributes to satisfying the Forecast Energy Requirement Demand Quantity shall receive a Day-Ahead Energy Imbalance Reserve Obligation.

(b) **Real-Time Energy Market Obligations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for unmetered load and any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by Generator Assets and External Transaction purchases at that Location.

(iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation** – Each Market Participant shall have for each settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(c) **<u>Real-Time Energy Market Obligations For Demand Response Resources</u>**

Real-Time Demand Reduction Obligation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation at each Location equal to the MWhs of demand reduction provided by Demand Response Resources at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction produced by a Demand Response Resource are equal to the sum of the demand reductions produced by its constituent Demand Response Assets calculated pursuant to Section III.8.4, where the demand reductions, other than MWhs associated with Net Supply, are increased by average avoided peak distribution losses.

(d) **<u>Real-Time Energy Market Deviations Excluding Demand Response Resource Contributions</u>** – For each Market Participant for each settlement interval, the ISO will determine the difference between the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) and the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)(1)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between (1) the Real-Time Locational Adjusted Net Interchange and (2) the Day-Ahead Locational Adjusted Net Interchange minus the Day-Ahead Demand Reduction Obligation for that Location.

(e) **Real-Time Energy Market Deviations For Demand Response Resources**

Real-Time Demand Reduction Obligation Deviation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(c)) and the Day-Ahead Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(a)(1)). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour.

(f) **Day-Ahead Energy Market Charge/Credit** – For each Market Participant for each settlement interval, the ISO will determine Day-Ahead Energy Market monetary positions representing a charge or credit for its net purchases from or sales to the ISO Day-Ahead Energy Market. The Day-Ahead Energy Market Energy Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational

Adjusted Net Interchanges multiplied by the Energy Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

(g) **Real-Time Energy Market Charge/Credit Excluding Demand Response Resources** – For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

(h) **Real-Time Energy Market Charge/Credit For Demand Response Resources** – For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market associated with Demand Response Resources. The charge or credit shall be equal to the sum of the Market Participant's Location-specific Real-Time Demand Reduction Obligation Deviations for that settlement interval multiplied by the Real-Time Locational Marginal Prices. Such charges and credits shall be allocated on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

(i) **Day-Ahead and Real-Time Congestion Revenue** – For each settlement interval, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission

System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Deviation Congestion Charge/Credits.

(j) **Day-Ahead Loss Revenue** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Day-Ahead Energy Market. The Day-Ahead Loss Revenue shall be equal to the sum of all Market Participants' Day-Ahead Energy Market Energy Charge/Credits and Day-Ahead Energy Market Loss Charge/Credits.

(k) **Day-Ahead Loss Charges or Credits** – For each settlement interval for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(j)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(l) **Real-Time Loss Revenue** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Real-Time Energy Market. The Real-Time Loss Revenue shall be equal to the sum of all Market Participants' Real-Time Energy Market Deviation Energy Charge/Credit and Real-Time Energy Market Deviation Loss Charge/Credit plus Non-Market Participant Transmission Customer loss costs. The ISO will then adjust Real-Time Loss Revenue to account for Inadvertent Energy Revenue, as calculated under Section III.3.2.1(o) and Emergency transactions as described under Section III.4.3(a).

(m) **Real-Time Loss Revenue Charges or Credits** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Real-Time Loss Revenue (Section III.3.2.1(l)). The Real-Time Loss Revenue Charges or Credits shall be equal to the Real-Time Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(n) **Non-Market Participant Loss** – Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the

Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(o) **<u>Inadvertent Energy Revenue</u>** – For each External Node, for each settlement interval the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at the External Node by the associated Real-Time Locational Marginal Price. For each settlement interval, the total Inadvertent Energy Revenue for a settlement interval shall equal the sum of the Inadvertent Energy Revenue values for each External Node for that interval.

(p) **<u>Inadvertent Energy Revenue Charges or Credits</u>** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(o)). The Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations, Real-Time Generation Obligations, and Real-Time Demand Reduction Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

(q)(1) **<u>Day-Ahead Ancillary Services Market Credit</u>** – Each Market Participant with a Day-Ahead Ancillary Services obligation shall receive a credit as follows:

(i) **Day-Ahead Ten-Minute Spinning Reserve Credit** – Each MWh of Day-Ahead Ten-Minute Spinning Reserve Obligation shall be credited the clearing price for Day-Ahead Ten-Minute Spinning Reserve calculated in accordance with Section III.2.6.2(a).

(ii) **Day-Ahead Ten-Minute Non-Spinning Reserve Credit** – Each MWh of Day-Ahead Ten-Minute Non-Spinning Reserve Obligation shall be credited the clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve calculated in accordance with Section III.2.6.2(a).

(iii) **Day-Ahead Thirty-Minute Operating Reserve Credit** – Each MWh of Day-Ahead Thirty-Minute Operating Reserve Obligation shall be credited the clearing price for Day-Ahead Thirty-Minute Operating Reserve calculated in accordance with Section III.2.6.2(a).

(iv) **Day-Ahead Energy Imbalance Reserve Credit** – Each MWh of Day-Ahead Energy Imbalance Reserve Obligation shall be credited the Forecast Energy Requirement Price calculated in accordance with Section III.2.6.2(b).

(q)(2) **<u>Day-Ahead Ancillary Services Market Close-Out Charge</u>** – Each Market Participant with a Day-Ahead Ancillary Services obligation shall receive a charge as follows:

(i) **Day-Ahead Flexible Response Services Charge** – Each MWh of Day-Ahead Ten-Minute Spinning Reserve Obligation, Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, and Day-Ahead Thirty-Minute Operating Reserve Obligation shall be charged the close-out charge rate, which shall be the greater of (a) the hourly Real-Time Hub Price less the Day-Ahead Ancillary Services Strike Price for the hour, and (b) zero.

(ii) **Day-Ahead Energy Imbalance Reserve Charge** – Each MWh of Day-Ahead Energy Imbalance Reserve Obligation shall be charged the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(i).

(q)(3) **<u>Allocation of Day-Ahead Flexible Response Services Credits/Charges</u>**

(i) The sum total credits calculated in accordance with Sections III.3.2.1(q)(1)(i) through (iii) for Day-Ahead Flexible Response Services shall be charged on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes (but not excluding the Real-Time Load Obligation incurred by Capacity Export Through Import Constrained Zone Transactions or FCA Cleared Export Transactions), and excluding Real-Time Load Obligation incurred by Storage DARDs.

(ii) The sum total close-out charges calculated in accordance with Section III.3.2.1(q)(2)(i) for Day-Ahead Flexible Response Services shall be credited on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes (but not excluding the Real-Time Load Obligation incurred by Capacity Export Through Import Constrained Zone Transactions or FCA Cleared Export Transactions), and excluding Real-Time Load Obligation incurred by Storage DARDs.

(q)(4) **<u>Allocation of Forecast Energy Requirement and Day-Ahead Energy Imbalance Reserve Credits/Charges</u>**

(i) **Forecast Energy Requirement Credit for Generator Assets and Demand Response Resources** – Each Market Participant with a Generator Asset or Demand Response Resource scheduled in the Day-Ahead Energy Market shall be credited the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(b), for each MWh of the resource's Day-Ahead energy obligation.

(ii) **Forecast Energy Requirement Credit for External Transaction Purchases** – Each Market Participant with an External Transaction purchase scheduled in the Day-Ahead Energy Market for which a corresponding External Transaction also has been properly submitted in the Real-Time Energy Market and submitted in the appropriate external Control Area shall be credited the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(b), for the lesser of (a) each MWh of the Day-Ahead energy obligation associated with the External Transaction and (b) each MWh offered for the corresponding External Transaction in the Real-Time Energy Market.

(iii) **Forecast Energy Requirement and Day-Ahead Energy Imbalance Reserve Charges** – The total amount credited in accordance with Sections III.3.2.1(q)(4)(i), III.3.2.1(q)(4)(ii), and III.3.2.1(q)(1)(iv) shall be charged on an hourly basis as follows:

a. Each Market Participant with an External Transaction sale scheduled in the Day-Ahead Energy Market shall receive a charge at the Forecast Energy Requirement Price for each MWh of such External Transaction sale.

b. For the difference between the total amount credited and the total amount charged to Market Participants with External Transaction sales scheduled in the Day-Ahead Energy Market as described in this subsection (iii), Market Participants shall receive a charge based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

(iv) **Day-Ahead Energy Imbalance Close-Out Credits** – The sum total close-out charges calculated in accordance with Section III.3.2.1(q)(2)(ii) for Day-Ahead Energy Imbalance Reserve shall be credited on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

III.3.2.1.1 Metered Quantity For Settlement.

For purposes of determining the Metered Quantity For Settlement, the five-minute telemetry value for a five-minute interval is the integrated value of telemetered data sampled over the five-minute period. For settlement calculations that require hourly revenue quality meter value from Resources or Load Assets that submit five-minute revenue quality meter data, the hourly revenue quality meter value is the average of five-minute revenue quality meter values for the hour. The Metered Quantity For Settlement is calculated as follows:

(a) For external interfaces, the Metered Quantity For Settlement is the scheduled value adjusted for any curtailment, except that for Inadvertent Interchange, the Metered Quantity For Settlement is the difference between the actual and scheduled values, where the actual value is

(i) calculated as the five-minute telemetry value plus the difference between the hourly revenue quality meter value and the hourly average telemetry value, or

(ii) the five-minute revenue quality meter value, if five-minute revenue quality meter data are available.

(b) For Resources (other than Demand Response Resources) or Load Assets that submit five-minute revenue quality meter data, the Metered Quantity For Settlement is the five-minute revenue quality meter value.

(c) For Resources with telemetry that submit hourly revenue quality meter data, the Metered Quantity For Settlement is calculated as follows:

(i) In the event that in an hour, the difference between the average of the five-minute telemetry values for the hour and the revenue quality meter value for the hour is greater than 20 percent of the hourly revenue quality meter value and greater than 10 MW then the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour. (For a Continuous Storage Facility, the difference between the average of the five-minute telemetry values and the revenue quality meter value will be determined using the net of the values submitted by its component Generator Asset and DARD.)

(ii) Otherwise, the Metered Quantity For Settlement is the telemetry profile of the revenue quality meter value equal to the five-minute telemetry value adjusted by a scale factor.

(d) For a Demand Response Resource, the Metered Quantity For Settlement equals the sum of the demand reductions of each of its constituent Demand Response Assets produced in response to a non-zero Dispatch Instruction, with the demand reduction for each such asset calculated pursuant to Section III.8.4.

(e) For Resources without telemetry that submit hourly revenue quality meter data, the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour.

(f) For Load Assets that submit hourly revenue quality meter data, the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour. For the purpose of this subsection (f), Load Assets do not include DARDs.

III.3.2.2 Metering and Communication.

(a) Revenue Quality Metering and Telemetry for Assets other than Demand Response Assets

The megawatt-hour data of each Generator Asset, Tie-Line Asset, and Load Asset must be metered and automatically recorded at no greater than an hourly interval using metering located at the asset's point of interconnection, in accordance with the ISO operating procedures on metering and telemetering. This metered value is used for purposes of establishing the hourly revenue quality metering of the asset.

The instantaneous megawatt data of each Generator Asset (except Settlement Only Resources) and each Asset Related Demand must be automatically recorded and telemetered in accordance with the requirements in the ISO operating procedures on metering and telemetering.

(b) Meter Maintenance and Testing for all Assets

Each Market Participant must adequately maintain metering, recording and telemetering equipment and must periodically test all such equipment in accordance with the ISO operating procedures on metering and telemetering. Equipment failures must be addressed in a timely manner in accordance with the requirements in the ISO operating procedures on maintaining communications and metering equipment.

(c) Additional Metering and Telemetry Requirements for Demand Response Assets

(i) Market Participants must report to the ISO in real time a set of telemetry data for each Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of Demand Response Assets as measured at their Retail Delivery Points, and shall be reported to the ISO every five minutes. For a Demand Response Resource to provide TMSR or TMNSR, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

(ii) If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

(iii) If the Market Participant or the ISO finds that the metering or telemetry devices do not meet the accuracy requirements specified in the ISO New England Manuals and Operating Procedures, the Market Participant shall promptly notify the ISO and indicate when it expects to resolve the accuracy problem(s), or shall request that the affected Demand Response Assets be retired. Once such an issue becomes known and until it is resolved, the demand reduction value and Operating Reserve capability of any affected Demand Response Asset shall be excluded from the Demand Response Resource with which it is associated.

(iv) The ISO may review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset. Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

(d) Overuse of Flat Profiling

In the event a Market Participant's telemetry is replaced with an hourly flat profile pursuant to Section III.3.2.1.1(c)(i) more than 20% of the online hours in a month and Market Participant's Resource has been online for over 50 hours in the month, the ISO may consult with the Market Participant for an explanation of the regular use of flat profiling and may request that the Market Participant address any telemetry discrepancies so that flat profiling is not regularly triggered.

Within 10 business days of issuance of such a request, the Market Participant 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 completing such remediation. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan.

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(i) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) For each settlement interval during an hour in which there are Emergency Energy purchases, the ISO calculates an Emergency Energy purchase charge or credit equal to the Emergency Energy purchase price minus the External Node Real-Time LMP for the interval, multiplied by the Emergency Energy quantity for the interval. The charge or credit for each interval in an hour is summed to an hourly value. The ISO allocates the hourly charges or credits to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are not following Dispatch Instructions; Self-Scheduled Resources (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts not following Dispatch Instructions; and Self-Scheduled Resources (other than Continuous Storage Generator Assets) not following their Day-Ahead Self-Scheduled amounts other than those following Dispatch Instructions; in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency Energy purchases are not included in this calculation. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs or credits attributable to the purchase of Emergency Energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) For each settlement interval during an hour in which there are Emergency Energy sales, the ISO calculates Emergency Energy sales revenue, exclusive of revenue from the Real-Time Energy Market, received from other Control Areas to provide the Emergency Energy sales. The revenues for each interval in an hour is summed to an hourly value. Hourly net revenues attributable to the sale of Emergency Energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are following Dispatch Instructions; and Self-Scheduled Generator Assets (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts following Dispatch Instructions; in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency Energy purchases are not included in this calculation. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency Energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of

Regional Network Load. Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

Non-Market Participant Transmission Customers shall be charged or credited for Congestion Costs as specified in Section III.1 of this Market Rule 1.

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 Eligible Data.

The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily Coincident Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines specified in the ISO New England Manuals for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

For revisions to meter data associated with assets that connect the New England Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the New England Control Area and the other Control Area to maintain an accurate record of inadvertent energy flow.

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

(b) Errors on the part of the ISO in the administration of Market Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the Correction Limit.

III.3.7 Eligibility for Billing Adjustments.

(a) Errors in Market Participant's statements resulting from errors in settlement software, errors in data entry by ISO personnel, and settlement production problems, that do not affect the day-ahead schedule or real-time system dispatch, will be corrected as promptly as practicable. If errors are identified prior to the issuance of final statements, the market will be resettled based on the corrected information.

(b) Calculations made by scheduling or dispatch software, operational decisions involving ISO discretion which affect scheduling or real-time operation, and the ISO's execution of mandatory dispatch directions, such as self-schedules or external contract conditions, are not subject to retroactive correction and resettlement. The ISO will settle and bill the Day-Ahead Energy Market as actually scheduled and the Real-Time Energy Market as actually dispatched. Any post-settlement issues raised concerning operating decisions related to these markets will be corrected through revision of operations procedures and guidelines on a prospective basis.

(c) While errors in reporting hourly metered data may be corrected (pursuant to Section III.3.8), Market Participants have the responsibility to ensure the correctness of all data they submit to the market settlement system.

(d) Disputes between Market Participants regarding settlement of internal bilateral transactions shall not be subject to adjustment by the ISO, but shall be resolved directly by the Market Participants unless they involve an error by the ISO that is subject to resolution under Section III.3.7(a).

(e) Billing disputes between Market Participants and the ISO or Non-Market Participants and the ISO shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

(f) Criteria for Meter Data Errors to be eligible for a Requested Billing Adjustment. In order to be eligible to submit a Requested Billing Adjustment due to a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process, a Market Participant must satisfy one of the following two conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than thirty-six (36) days prior to the Correction Limit for Directly Metered Assets and no later than two (2) days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; or (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader and reported to the ISO by the Meter Data Error RBA Submission Limit, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per Asset over a calendar month. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website. Errors in telemetry values used in calculating Metered Quantity For Settlement are not eligible for correction under this Section III.3.8.

(b) Within three Business Days of the receipt of an RBA form for a Meter Data Error as defined in Section 6.3.1 of the ISO New England Billing Policy, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Meter Data Error correction ("Notice of Meter Data Error Correction"), including, subject to the provisions of the ISO New England Information Policy, the specific details of the correction and the identity of the affected metering domains and the affected Host Participant Assigned Meter Readers. The "Notice of Meter Data Error Correction" shall identify a specific representative of the ISO to whom all communications regarding the matter are to be sent.

(c) In order for a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process to be eligible for correction, the Meter Data Error must satisfy one of the following conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than 36 days prior to the Correction Limit for Directly Metered Assets and no later than two days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per asset over a calendar month; and (3) if the Meter Data Error involves only Coincident Peak Contribution values, the average of the daily Meter Data Errors involving Coincident Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

(d) For a Meter Data Error, the Host Participant Assigned Meter Reader must submit to the ISO corrected meter data for Directly Metered Assets prior to the 46th calendar day after the Meter Data Error RBA Submission Limit. Corrected metered data for Profiled Load Assets and Coincident Peak Contribution values, must be submitted to the ISO by the Host Participant Assigned Meter Reader prior to the 87th calendar day after the Meter Data Error RBA Submission Limit. Corrected internal bilateral transactions data must be submitted to the ISO by a Market Participant prior to the 91st calendar day after the Meter Data Error RBA Submission Limit.

Any corrected data received after the specified deadlines is not eligible for use in the settlement process.

The Host Participant Assigned Meter Reader or Market Participant, as applicable, must confirm as part of its submission of corrected data that the eligibility criteria described in Section III.3.8(c) of Market Rule 1 have been satisfied.

To the extent that the correction of a Meter Data Error is for a Directly Metered Asset that affects multiple metering domains, all affected Host Participant Assigned Meter Readers or Assigned Meter Readers must notify the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit that the corrected Directly Metered Asset data is acceptable to them in order for the ISO to use the corrected data in the final settlement calculations. The Host Participant Assigned Meter Reader for the Directly Metered Asset is responsible for initiating an e-mail to every affected Host Participant Assigned Meter Reader or Assigned Meter Reader in order to obtain such acceptance and shall coordinate delivery of such acceptance to the ISO. The Host Participant Assigned Meter Reader for the Directly Metered Asset is also responsible for submitting all corrected and agreed upon Directly Metered Asset data to the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit.

(e) After the submission of corrected meter and internal bilateral transactions data, the ISO will have a minimum of 30 calendar days to administer the final settlement based on that data. Revised data will be used to recalculate all charges and credits. Revised data will also not be used to recalculate Demand Resource Seasonal Peak Hours. The results of the final settlement will then be included in the next Invoice containing Non-Hourly Charges and the ISO will provide to the Chair of the NEPOOL Budget and Finance Subcommittee written notification that the final settlement has been administered.

III.4 Rate Table

III.4.1 Offered Price Rates.

Day-Ahead energy, Day-Ahead Ancillary Services, Real-Time energy, Regulation, Real-Time Operating Reserve, Forward Reserve, NCPC, Congestion Cost and transmission loss costs are based on offers and bids submitted to the ISO as specified in this Market Rule 1.

III.4.2 [Reserved.]

III.4.3 Emergency Energy Transaction.

The pricing for Emergency Energy and New Brunswick Security Energy purchases and sales will be determined in accordance with:

(a) an applicable agreement with an adjacent Control Area for Emergency and/or New Brunswick Security Energy purchases and sales, or

(b) arrangements made by the ISO with Market Participants, in accordance with procedures defined in the ISO New England Manuals, to purchase Emergency Energy offered by such Market Participant from External Transactions that are not associated with Import Capacity Resources. The ISO shall select offers to sell Emergency Energy made by Market Participants to the ISO on a least cost basis and the selected Market Participants shall receive payment for energy delivered at the higher of their offer price or the Real-Time Price at the applicable External Node. Such Emergency Energy purchases from Market Participants shall not be eligible to set Real-Time Prices.

III.5 Transmission Congestion Revenue & Credits Calculation

For purposes of this Section III.5, unless otherwise expressly stated, the settlement interval is five minutes. 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.

III.5.1 Non-Market Participant Transmission Congestion Cost Calculation.

III.5.1.1 Calculation by ISO.

When the transmission system is operating under constrained conditions, the ISO shall calculate Congestion Costs.

III.5.1.2 General.

The basis for the Congestion Costs shall be the differences in the Congestion Component of the Locational Marginal Prices between points of delivery and points of receipt, as determined in accordance with Section III.2 of this Market Rule 1.

III.5.1.3 [Reserved.]

III.5.1.4 Non-Market Participant Transmission Customer Calculation.

Congestion Costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Congestion Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Congestion Component of the Real-Time Price at the source point or New England Control Area boundary source interface. Non-Market Participants using TOUT Service for deliveries through the New England Control Area shall be included in the determination of the Congestion Costs.

III.5.2 Transmission Congestion Credit Calculation.

III.5.2.1 Eligibility.

Except as provided in Section III.A.12 of Appendix A, each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total monthly Transmission Congestion Revenues collected.

III.5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the FTRs held at the time of the constrained hour.

(b) FTRs shall be awarded to winning bidders in the FTR Auctions pursuant to Section III.7.

(i) An entity that acquires an FTR through the FTR Auction shall automatically be recognized by the ISO as the registered FTR Holder of that FTR, subject to having already met the eligibility criteria for bidding in the FTR Auction. The registered FTR Holder shall be entitled to receive or be obligated to make FTR payments arising from such FTR in accordance with Section III.5.2.

(ii) An entity that acquires an FTR through the FTR Auction may elect to hold it, or sell it in the FTR Auction. The ISO shall settle FTRs only with the registered FTR Holders. At any given time, each FTR shall have only one registered FTR Holder.

III.5.2.3 [Reserved.]

III.5.2.4 Target Allocation to FTR Holders.

A target allocation of Transmission Congestion Credits for each FTR Holder shall be determined for all applicable FTRs. Each FTR shall be multiplied by the Day-Ahead Price Congestion Component differences for the associated receipt and delivery points. This calculation will result in a positive or negative FTR target allocation. All negative target allocations are obligations to pay. All positive target allocations will be summed for an FTR Holder for the month and compensated as Transmission Congestion Credits under Section III.5.2.5.

III.5.2.5 Calculation of Transmission Congestion Credits.

(a) The total Transmission Congestion Revenue available for the month shall be equal to the sum of: (i) the hourly Day-Ahead Congestion Revenue amounts for the month, (ii) the Real-Time Congestion Revenue amounts for the month plus Congestion Costs collected under Section III.5.1.4, and (iii) the negative FTR target allocations calculated under Section III.5.2.4.

(b) The sum of all monthly positive target allocations, as determined in Section III.5.2.4, shall be compared to the Transmission Congestion Revenue for the current month. If the sum of all monthly positive target allocations is less than the Transmission Congestion Revenue for the current month, the Transmission Congestion Credit for each FTR Holder shall be equal to its total monthly positive target allocation. All remaining Transmission Congestion Revenues from the current month shall be carried over to the end of the calendar year.

(c) If the sum of all the monthly positive target allocations is greater than the Transmission Congestion Revenue for the current month, each FTR Holder shall be assigned a share of the total Transmission Congestion Revenue for the current month in proportion to its total monthly positive target allocations.

III.5.2.6 Distribution of Excess Congestion Revenue.

If there is any Transmission Congestion Revenue at the end of the calendar year, this amount shall be proportionally allocated to any remaining unpaid monthly positive target allocations plus interest on the unpaid monthly positive target allocations in the months of that year, but shall not exceed an amount equal to the unpaid monthly positive target allocation plus interest on the unpaid monthly positive target allocations in the months of the calendar year. Any remaining surplus Transmission Congestion Revenue shall be allocated to the entities who paid Congestion Costs in that calendar year in proportion to the amount of total Congestion Costs paid during the year.

III.6 Local Second Contingency Protection Resources

III.6.1 [Reserved.]

III.6.2 Day-Ahead and Real-Time Energy Market.

When establishing operating schedules, the ISO will select and identify Local Second Contingency Protection Resources on a not unduly discriminatory basis in accordance with the procedures defined in the ISO New England Manuals. Appendix A will determine which, if any, Supply Offers will be adjusted. The ISO will also record, in an auditable log, the reason the Resource was selected.

III.6.2.1 Special Constraint Resources.

When establishing operating schedules, at the request of a Transmission Owner or distribution company in order to maintain area reliability, the ISO will commit and dispatch Generator Assets to provide relief for constraints not reflected in the ISO's systems for operating the New England Transmission System or the ISO's operating procedures in accordance with the procedures defined in the ISO New England Manuals. The ISO will also record, in an auditable log, the designation of such a Generator Asset as a Special Constraint Resource and the name of the requesting Transmission Owner or distribution company. Any NCPC Charge associated with the Real-Time operation of the Special Constraint Resource is charged in accordance with the provisions of Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

III.6.3 [Reserved.]

III.7 Financial Transmission Rights Auctions

III.7.1 Auctions of Financial Transmission Rights.

Periodic auctions ("FTR Auctions") to allow Eligible FTR Bidders to acquire or FTR Holders to sell FTRs shall be conducted by the ISO in accordance with the provisions of this Section. Non-Market Participants that want to participate in the FTR Auction and have satisfied the applicable financial assurance criteria will be charged a one time FTR Registration Fee of $5,000.

III.7.1.1 Auction Period and Scope of Auctions.

(a) FTR Auctions shall be held on an annual and monthly basis.

(b) The annual FTR Auction shall be conducted for FTRs effective for a single calendar year in two sequential rounds. Twenty-five percent of the available network capacity shall be available for the initial round of the annual FTR Auction. The FTRs that remain feasible with fifty percent of the network capacity available and after deducting the network capability associated with FTRs sold in the initial round shall be made available during the second round of the annual FTR Auction.

(c) The ISO shall conduct monthly FTR Auctions, after the completion of the annual FTR Auction, every month. A monthly FTR shall be effective for a single full calendar month. The monthly FTR Auctions shall include separate auctions for every remaining month in the calendar year. FTRs shall be made available for monthly auctions as follows:

(i) When FTRs for a month are auctioned for the final time, all FTRs that remain feasible will be made available, after accounting for all FTRs transacted in the annual FTR Auctions and all FTRs transacted in previous auctions for the relevant month.

(ii) For all other monthly auctions all FTRs that remain feasible with fifty percent of the network capacity available will be made available after accounting for all FTRs transacted in the annual FTR Auctions and all FTRs transacted in previous auctions for the relevant month.

III.7.1.2 FTR Auctions Assumptions.

For annual FTR Auctions, the auction assumptions, including the modeling assumptions to be used for the FTR Auctions and dates and times for the opening and closing of bid submission windows will be announced by the ISO no later than 90 days prior to the first effective day of the FTRs to be auctioned.

For monthly FTR Auctions, the auction assumptions, including the modeling assumptions to be used for the FTR Auctions and dates and times for the opening and closing of bid submission windows will be announced by the ISO no later than 40 days prior to the first effective day of the FTRs to be auctioned.

III.7.2 Financial Transmission Rights Characteristics.

III.7.2.1 Reconfiguration of Financial Transmission Rights.

Using an appropriate linear programming model, the ISO shall reconfigure the FTRs offered or otherwise available for sale in any auction to maximize the value to the bidders of the FTRs sold, provided that any FTRs acquired at auction shall be simultaneously feasible in combination with those FTRs outstanding at the time of the auction and not sold in the auction. The linear programming model shall, while respecting transmission constraints and the maximum megawatt quantities of the bids and offers, select the set of simultaneously feasible FTRs with the highest total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers.

III.7.2.2 Specified Locations.

Auction bids for FTRs may specify any combination of receipt and delivery locations represented in the State Estimator model for which the ISO calculates and posts Locational Marginal Prices. Auction bids may specify receipt and delivery points from locations outside of the New England Control Area to locations inside the New England Control Area, from locations within the New England Control Area to locations outside of the New England Control Area, or to and from locations within the New England Control Area. Congestion over interfaces associated with non-PTF external tie lines is not subject to LMP-based congestion management and, therefore, no FTRs across such interfaces will be included in the FTR Auctions.

III.7.2.3 Transmission Congestion Revenues.

FTRs shall entitle holders thereof to credits only for Transmission Congestion Revenue, and shall not confer a right to credits for payments arising from or relating to transmission congestion made to any entity other than the ISO.

III.7.2.4 [Reserved.]

III.7.3 Auction Procedures.

III.7.3.1 Role of the ISO.

FTRs auctions shall be conducted by the ISO in accordance with standards and procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures, such standards and procedures to be consistent with the requirements of this Market Rule.

III.7.3.2 [Reserved.]

III.7.3.3 [Reserved.]

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

The ISO will conduct separate auctions simultaneously for on-peak and off-peak periods. On-peak FTRs shall cover the periods from 7:00 a.m. up to the hour ending at 11:00 p.m. on Mondays through Fridays, except holidays as defined in the ISO New England Manuals and ISO New England Administrative Procedures. Off-peak FTRs shall cover the periods from 11:00 p.m. up to the hour ending 7:00 a.m. on Mondays through Fridays and all hours on Saturdays, Sundays, and NERC holidays as defined in the ISO New England Manuals and ISO New England Administrative Procedures. Each bid shall specify whether it is for an on-peak or off-peak period.

III.7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase FTRs shall be submitted during the applicable period set forth in Section III.7.1.2, and shall be in the form specified by the ISO in accordance with the requirements set forth below.

(b) Offers to sell shall identify the specific FTRs, by megawatt quantity and receipt and delivery points, offered for sale. An offer to sell a specified megawatt quantity of FTRs shall constitute an offer to sell a quantity of FTRs equal to or less than the specified quantity. An offer to sell may not specify a minimum quantity being offered. Each offer may specify a reservation price, below which the offeror does not wish to sell the FTR. Offers shall be subject to such applicable standards for the financial assurance of the offeror or for the posting of security for performance as the ISO shall establish.

(c) Bids to purchase shall specify the megawatt quantity, price per megawatt, and receipt and delivery points of the FTR that the bidder wishes to purchase. A bid to purchase a specified megawatt quantity of FTRs shall constitute a bid to purchase a quantity of FTRs equal to or less than the specified quantity. A bid to purchase may not specify a minimum quantity that the bidder wishes to purchase. A bid may specify as receipt or delivery points any Location for which the ISO calculates and posts Locational

Marginal Prices in accordance with Section III.2 of this Market Rule and may include FTRs for which the associated Transmission Congestion Credits may have negative values. Bids shall be subject to such applicable standards for the financial assurance of the bidder or for the posting of security for performance as the ISO shall establish.

(d) Bids and offers shall be specified to the nearest 0.1 megawatt and the quantity shall be greater than zero.

III.7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of each bidding period, the ISO will create a base FTR power flow model that includes all outstanding FTRs that have previously been awarded for the period for which the auction was conducted and that were not offered for sale in the auction. As detailed in the auction assumptions described in Section III.7.1.2, the base FTR model for the annual and monthly FTR Auctions will reflect the appropriate network topology, transmission operating limits, estimated scheduled transmission outages, and outages of individual generating units to the extent that such outages impact voltage or stability limits. The base FTR models also will include estimated uncompensated parallel flows into each interface point of the New England Control Area.

(b) In accordance with the requirements of this Section and subject to all applicable transmission constraints and reliability requirements, the ISO shall determine the simultaneous feasibility of all outstanding FTRs not offered for sale in the auction and of all FTRs that could be awarded in the auction for which bids were submitted. The winning bids shall be determined from an appropriate linear programming model that, while respecting transmission constraints and the maximum megawatt quantities of the bids and offers, selects the set of simultaneously feasible FTRs with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected FTRs and there are insufficient FTRs to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the FTRs that can be awarded.

(c) FTRs shall be sold at the market-clearing price for FTRs between specified pairs of receipt and delivery points, as determined by the bid value of the marginal FTR that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all FTR paths based on the bid value of the marginal FTRs, which are those FTRs with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each FTR's path relative to the marginal FTRs' paths flow sensitivities on the binding transmission constraints.

III.7.3.7 Announcement of Winners and Prices.

(a) After the close of the first round of the annual FTR Auction, in accordance with the schedule published in the auction assumptions and prior to the open of the bidding window for the final-round annual auctions, the ISO shall post the auction prices and FTRs cleared between eligible bidding locations, as specified in Section III.7.2.2, excluding the identity of the winning bidder. The identities of winning bidders and the quantities of FTRs cleared by individual bidders in the first round of the annual auction will not be published until the close of the final round of the annual FTR Auction.

After the close of the final round of the annual FTR Auction, the ISO shall post, in accordance with the schedule set forth in the auction assumptions and prior to the open of the bidding window for monthly auctions, the winning bidders, the megawatt quantity, and the receipt and delivery points for each FTR awarded in the annual auction and the price at which each FTR was awarded.

(b) After the close of the monthly FTR Auction process, in accordance with the schedule set forth in the auction assumptions and prior to the effective date of the auctioned FTRs, the ISO shall post the winning bidders, the megawatt quantity, and the receipt and delivery points for each FTR awarded in the auction and the price at which each FTR was awarded. The FTR awards and prices shall be final as posted and not subject to correction or other adjustment, and shall be used for purposes of settlement, except as provided in subsections (d) and (e).

(c) Before posting the final FTR awards and prices, the ISO shall make a good faith effort when clearing the FTR Auction to discover and correct any errors that may occur due to database, software or similar errors of the ISO or its systems.

(d) If the ISO determines based on a reasonable belief that there may be one or more errors in the final FTR awards and prices or if no FTR awards or prices 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 11:59 p.m. of the third business day following the applicable posting deadlines specified in subsections (a) or (b), as appropriate, a notice that the FTR awards and prices are provisional and subject to correction or unavailable for initial publishing. The ISO shall confirm within three business days of posting a notice pursuant to this subsection whether there was an error in the FTR awards and prices and shall post a notice stating its findings.

(e) Within three business days after posting an initial notice pursuant to subsection (d); the ISO shall either: (1) publish final or corrected FTR awards and prices, or (2) in the event that the ISO is unable to calculate and post final or corrected FTR awards and prices due to exigent circumstances not contemplated in this market rule, make an emergency filing with the Commission detailing the exigent circumstance, which will not allow final FTR awards and prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

(f) Results of the on-peak auction and off-peak auction will be posted separately. The ISO shall not disclose the price specified in any bid to purchase or the reservation price specified in any offer to sell.

III.7.3.8 Auction Settlements.

All buyers and sellers of FTRs between the same points of receipt and delivery shall pay or be paid the market-clearing price, as determined in the auction, for such FTRs.

III.7.3.9 Allocation of Auction Revenues.

All auction revenues, net of payments to entities selling FTRs into the auction, shall be allocated as specified under Appendix C of this Market Rule.

III.7.3.10 Simultaneous Feasibility.

The ISO shall make the simultaneous feasibility determinations specified herein using appropriate power flow models of contingency-constrained dispatch. Such determinations shall take into account outages, network model-related changes, and expected configuration of transmission facilities in accordance with Section III.7.3.6(a). The goal of the simultaneous feasibility determination shall be to ensure that there are sufficient Transmission Congestion Revenues to satisfy all FTR obligations for the auction period under expected conditions.

III.7.3.11 [Reserved.]

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

When the ISO has the necessary software and hardware, the FTR Auctions shall allow for the acquisition of FTRs that do not create potential obligations to pay.

III.8 Additional Requirements for Demand Response Assets and Demand Response Resources

III.8.1 Registration and Aggregation

III.8.1.1 Demand Response Asset Registration and Aggregation

(a) A Demand Response Asset must have a Maximum Interruptible Capacity of at least 10 kW.

(b) A Demand Response Asset must have a single Retail Delivery Point and be registered at a single Node, unless it meets the conditions for aggregation in Section III.8.1.1(f).

(c) No more than one Demand Response Asset may be registered at a Retail Delivery Point.

(d) 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.

(e) A facility with a Net Supply Capability of 5 MW or more may not be registered as a Demand Response Asset if its Net Supply Capability is greater than its Maximum Facility Load.

(f) A Demand Response Asset may be the aggregate demand reduction capability of multiple end-use customers with multiple Retail Delivery Points within a single DRR Aggregation Zone if (i) the demand reduction from each Retail Delivery Point is less than 10 kW and (ii) the demand at all Retail Delivery Points represents a homogeneous population as determined by the ISO. A Demand Response Asset that meets these conditions for aggregation must be registered at a DRR Aggregation Zone.

(g) A Demand Response Asset with a Maximum Interruptible Capacity equal to or greater than 5 MW at a single Retail Delivery Point must be registered as a single Demand Response Resource at a single Node.

(h) The metering and communication equipment associated with each Demand Response Asset must meet the requirements in Section III.3.2.2 and ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.

(i) Upon request, the ISO will inform a load serving entity if (i) any of its end-use customers' facilities are registered as Demand Response Assets and (ii) the load reduction capability of any such Demand Response Assets.

III.8.1.2 Demand Response Resource Registration and Aggregation

(a) A Demand Response Resource must be comprised of one or more Demand Response Assets within the same DRR Aggregation Zone.

(b) A Demand Response Resource must be capable of at least 0.1 MW of demand reduction.

(c) A Demand Response Resource cannot be composed of: (i) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand reduction capability to be bid into the ISO-administered markets or programs; or (ii) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand reduction capability to be bid into the ISO-administered markets or programs.

(d) Market Participants must assign Demand Response Assets to Demand Response Resources such that the number of a Market Participant's Demand Response Resources within a single DRR Aggregation Zone does not exceed one plus the Market Participant's total demand reduction capability in the DRR Aggregation Zone rounded up to the nearest whole megawatt value. If a Market Participant becomes noncompliant with this Section III.8.1.2(d), the Market Participant shall consult with the ISO to develop a plan, subject to ISO approval, that will result in compliance with this Section.

III.8.2 Demand Response Baselines

(a) A Demand Response Baseline is calculated for each Demand Response Asset for the following three day types:

(i) weekdays (excluding Demand Response Holidays);

(ii) Saturdays; and

(iii) Sundays and Demand Response Holidays.

(b) A Market Participant shall not take any action to create or maintain a Demand Response Baseline that exceeds the typical electricity consumption levels of its end-use metered customers expected in the normal course of business.

(c) If a Demand Response Asset produces Net Supply in an interval, that Net Supply will be used in the Demand Response Baseline calculations for that interval.

III.8.2.1 Determining the Weekday Non-Holiday Demand Response Baseline

A Demand Response Asset's weekday (non-Demand Response Holiday) Demand Response Baseline in each five-minute interval is equal to the average of the asset's meter data for the same five-minute interval from 10 prior non-Demand Response Holiday weekdays, as follows:

(a) For a Demand Response Asset without a weekday Demand Response Baseline, the initial weekday Demand Response Baseline will be created using meter data from the first 10 consecutive non-Demand Response Holiday weekdays with a complete set of five-minute interval meter data.

(b) For a Demand Response Asset that has established a weekday Demand Response Baseline, the baseline will be updated using meter data from:

(i) the 10 most recent of the previous 30 non-Demand Response Holiday weekdays, excluding days during which: (1) the resource associated with the asset received a Dispatch Instruction for an amount greater than 0 MW or (2) the asset was on a forced or scheduled curtailment as described in Section III.8.3;

(ii) if there are fewer than 10 such days, then meter data from additional days will be used (until a total of 10 days have been identified) including, first, the most recent days during which the resource associated with the asset received a Dispatch Instruction for an amount greater than 0 MW and, second, the most recent days during which the asset was on a forced or scheduled curtailment as described in Section III.8.3.

III.8.2.2 Determining the Saturday Demand Response Baseline

A Demand Response Asset's Saturday Demand Response Baseline in each five-minute interval is equal to the average of the asset's meter data for the same five-minute interval from five prior Saturdays as follows:

(a) For a Demand Response Asset without a Saturday Demand Response Baseline, the Saturday Demand Response Baseline will be created using meter data from the first five consecutive Saturdays with a complete set of five-minute interval meter data.

(b) For a Demand Response Asset that has established a Saturday Demand Response Baseline, the baseline will be updated using meter data from:

(i) the five most recent Saturdays of the previous 42 calendar days, excluding Saturdays during which: (1) the resource associated with the asset received a Dispatch Instruction for an amount greater than 0 MW or (2) the asset was on a forced or scheduled curtailment as described in Section III.8.3.

(ii) if there are fewer than five such Saturdays, then, in addition to those days, meter data from the most recent Saturdays will be used, until five days are identified.

III.8.2.3 Determining the Sunday and Demand Response Holiday Demand Response Baseline

A Demand Response Asset's Sunday and Demand Response Holiday Demand Response Baseline in each five-minute interval is equal to the average of the asset's meter data for the same five-minute interval from five prior Sundays or Demand Response Holidays as follows:

(a) For a Demand Response Asset without a Sunday and Demand Response Holiday Demand Response Baseline, the Sunday and Demand Response Holiday Demand Response Baseline will be created using meter data from the first five consecutive Sundays and Demand Response Holidays with a complete set of five-minute interval meter data.

(b) For a Demand Response Asset that has established a Sunday and Demand Response Holiday Demand Response Baseline, the baseline will be updated using meter data from:

  (i) the five most recent Sundays or Demand Response Holidays of the previous 42 calendar days, excluding Sundays or Demand Response Holidays during which: (1) the resource associated with the asset received a Dispatch Instruction for an amount greater than 0 MW or (2) the asset was on a forced or scheduled curtailment as described in Section III.8.3;

  (ii) if there are fewer than five such Sundays or Demand Response Holidays, then, in addition to those days, meter data from the most recent Sunday or Demand Response Holiday will be used, until five days are identified.

III.8.2.4 Adjusted Demand Response Baseline

(a) The ISO will also calculate an adjusted Demand Response Baseline for each Demand Response Asset in each interval in which its associated Demand Response Resource receives a non-zero Dispatch Instruction.

(b) The adjusted Demand Response Baseline shall equal the Demand Response Baseline plus an adjustment (which may be positive or negative) equal to the average megawatt difference between the Demand Response Asset's metered demand (which may reflect Net Supply) and its Demand Response Baseline during the three most recently completed five-minute intervals prior to the issuance of the start-up instruction; provided that, if there was a non-zero Dispatch Instruction during any of those three five-minute intervals, the adjustment during the current dispatch will equal the adjustment during the prior dispatch.

(c) For Demand Response Assets that cannot produce Net Supply, the adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load.

(d) For Demand Response Assets that can produce Net Supply, the adjusted Demand Response Baseline shall not be less than (that is, shall not result in expected output at the Retail Delivery Point that exceeds) the asset's Net Supply Capability and shall not exceed the asset's Maximum Load.

III.8.3 Demand Response Asset Forced and Scheduled Curtailments

In addition to complying with the outage requirements described in ISO New England Operating Procedure No. 5, a Market Participant with a Demand Response Asset must abide by the following curtailment procedures.

(a) Forced Curtailment – A Market Participant with a Demand Response Asset may notify the ISO of a forced curtailment, that is, a reduction in demand resulting from actions outside the control of the Demand Response Asset or the Market Participant subject to the forced curtailment.

(b) Scheduled Curtailment – At least seven calendar days prior to the start of the curtailment, a Market Participant with a Demand Response Asset may notify the ISO of a scheduled curtailment, that is, a reduction in demand resulting from a scheduled plant shutdown or scheduled maintenance of energy consuming equipment. A scheduled curtailment may be no shorter than a single calendar day and the total duration of scheduled curtailments per Capacity Commitment Period may not exceed 14 calendar days.

(c) Offers and Settlement – Except for the first day of a forced curtailment, (i) Demand Reduction Offer parameters may not include any contributions from a Demand Response Asset on a forced or scheduled curtailment and (ii) a Demand Response Asset on a forced or scheduled curtailment shall not be eligible for payment in the Real-Time Energy Market.

III.8.4 Demand Response Asset Energy Market Performance Calculations

(a) The ISO will calculate the demand reduction contribution of a Demand Response Asset in each interval in which its associated Demand Response Resource has received a non-zero Dispatch Instruction following the conclusion of the Demand Response Resource Notification Time. The demand reduction contribution by a Demand Response Asset to its Demand Response Resource shall equal the difference between the adjusted Demand Response Baseline of the Demand Response Asset (with the adjustment calculated as described in Section III.8.2.4) and the metered demand of the Demand Response Asset, except as follows:

(i) On the first day of a forced curtailment, a Demand Response Asset's demand reduction shall equal the difference between the Demand Response Baseline of the Demand Response Asset and the metered demand of the Demand Response Asset; and

(ii) A Demand Response Asset shall be assessed a zero demand reduction on any day of a forced curtailment other than the first day; on any day of a scheduled curtailment; in any interval in which there is insufficient data to calculate the Demand Response Baseline; and in any interval in which the Market Participant fails to comply with the Demand Response Asset metering and communication requirements in Section III.3.2.2 or ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.

(b) Notwithstanding the foregoing, a Demand Response Asset's demand reduction for purposes of determining Actual Capacity Provided during a Capacity Scarcity Condition shall be calculated pursuant to Section III.13.7.2.2.

III.9 Forward Reserve Market

The Forward Reserve Market is a market to procure TMNSR and TMOR on a forward basis to satisfy Forward Reserve requirements.

III.9.1 Forward Reserve Market Timing.

A Forward Reserve Auction will be held approximately two months in advance of each Forward Reserve Procurement Period. The Forward Reserve Auction input parameters and assumptions will be evaluated, published and reviewed with Market Participants prior to the Forward Reserve Auction. The final Forward Reserve Auction will be held approximately two months in advance of the final Forward Reserve Procurement Period as described in this Section III.9.1, and no Forward Reserve Auctions shall be conducted thereafter.

The Forward Reserve Procurement Periods shall be the Winter Capability Period (October 1 through May 31) or the Summer Capability Period (June 1 through September 30), as applicable. The final Forward Reserve Procurement Period shall run from October 1, 2024 through February 28, 2025.

The Forward Reserve Delivery Period shall be hour ending 0800 through hour ending 2300 for each weekday of the Forward Reserve Procurement Period excluding those weekdays that are defined as NERC holidays.

III.9.2 Forward Reserve Requirements.

The ISO shall conduct an advance purchase of capability to satisfy the expected Forward Reserve requirements for the system and each Reserve Zone as calculated by the ISO in accordance with the following procedures and as specified more fully in the ISO New England Manuals. The Forward Reserve requirements will be specified as part of the Forward Reserve Auction parameters and will be published and reviewed with Market Participants prior to each Forward Reserve Auction.

III.9.2.1 System Forward Reserve Requirements.

The Forward Reserve requirements for the New England Control Area will be based on the forecast of the first and second contingency supply losses for the next Forward Reserve Procurement Period and will consist of the following:

(i) One half of the forecasted first contingency supply loss will be specified as the minimum forward ten-minute reserve requirement to be purchased.

(ii) The minimum forward ten-minute reserve requirement described in subsection (i) will be increased if system conditions forecasted for the Forward Reserve Procurement Period indicate that the TMNSR available during the period would otherwise be insufficient to meet Real-Time Operating Reserve requirements. The increase shall be calculated to account for: (a) any historical under-performance of Resources dispatched in response to a System contingency and (b) the likelihood that more than one half of the forecasted first contingency supply loss will be satisfied using TMNSR.

(iii) The minimum forward ten-minute reserve requirement plus one half of the second contingency supply loss will be specified as the minimum forward total reserve requirement to be purchased.

(iv) The minimum forward total reserve requirement described in subsection (iii) will be increased by an amount of Replacement Reserve as specified in ISO New England Operating Procedure No. 8.

The requirements specified above, further adjusted to respect the additional provisions described in Section III.9.2.2, represent the set of requirements that will be input into the Forward Reserve Auction.

III.9.2.2 Zonal Forward Reserve Requirements.

Zonal Forward Reserve requirements will be established for each Reserve Zone. The zonal Forward Reserve requirements will reflect the need for 30-minute contingency response to provide 2nd contingency protection for each import constrained Reserve Zone. The zonal Forward Reserve requirements can be satisfied only by Resources that are located within a Reserve Zone and that are capable of providing 30-minute or higher quality reserve products.

The ISO shall establish the zonal Forward Reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each Reserve Zone for like Forward Reserve Procurement Periods. The ISO will commence the analysis on February 1 or the first business day thereafter for the subsequent summer Forward Reserve Procurement Period and on June 1 or the first business day thereafter for the subsequent winter Forward Reserve Procurement Period.

These daily peak hour requirements will be aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each Reserve Zone will establish the zonal requirement.

In the event of a change in the configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource the rolling two-year historical analysis will be calculated in a manner that reflects the change in configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource as of the commencement date of the analysis provided that the following conditions are met:

(a) Change in Configuration of the Transmission System

Any change in the configuration of the transmission system must have been placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

If the change in the configuration of the transmission system consists of a new facility or upgrade of an existing facility, the facility must have operated at an availability level of at least 95% for the period beginning with its in service date and ending on January 31 prior to the summer Forward Reserve Procurement Period or ending on May 31 prior to the winter Forward Reserve Procurement Period.

(b) Addition, Deactivation or Retirement of a Major Generating Resource, Dispatchable Asset Related Demand or Demand Response Resource.

For the addition of a new Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource, the Resource must be placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period. For the deactivation or retirement of a Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource, the Resource must have been removed from service on or before January 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer

Forward Reserve Procurement Period or on or before May 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

The modified historical data set will be composed of actual data used in the operation of the reconfigured system and historical (pre-reconfiguration) data adjusted for the impact of the system reconfiguration. Pre-reconfiguration data will be revised by substituting values from the historical data set that are no longer valid with corresponding values used in the operation of the reconfigured system.

The zonal Forward Reserve requirements will be recalculated using the modified historical data set until the rolling two-year historical data set reflects a common system configuration.

III.9.3 Forward Reserve Auction Offers.

Forward Reserve Auction Offers for TMNSR and TMOR shall be (a) made on a $/MW-month basis, (b) made on a Reserve Zone specific basis, (c) made on a non-Resource specific basis and (d) shall be less than or equal to the Forward Reserve Offer Cap. Forward Reserve Auction Offers shall be submitted to the ISO by Market Participants. The Market Participants are responsible for complying with the requirements of this Section III.9 if the Forward Reserve Auction Offer is accepted. Notwithstanding the publication timeline specified in Section 3(a) of the ISO New England Information Policy, the ISO shall publish Forward Reserve Auction Offer data on the first day of the twelfth calendar month following the month during which the applicable supply offers were in effect, and not prior thereto.

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

The Forward Reserve Auction shall simultaneously clear Forward Reserve Auction Offers to meet the Forward Reserve requirements for the system and each Reserve Zone using a mathematical programming algorithm. The objective of the mathematical programming based Forward Reserve Auction clearing is to minimize the total cost of Forward Reserve procured to meet the Forward Reserve requirements. The Forward Reserve Clearing Price for each Reserve Zone will reflect the cost to serve the next increment of reserve in that Reserve Zone based on the submitted offers. The Forward Reserve Auction algorithm substitutes higher quality TMNSR for lower quality TMOR to meet system or Reserve Zone Forward Reserve requirements when it is economical to do so provided that no constraints are violated.

The Forward Reserve Auction algorithm shall also utilize excess Forward Reserve in one Reserve Zone to meet the Forward Reserve requirements of another Reserve Zone or the system provided that the Forward Reserve can be delivered such that no constraints are violated. In addition, the Forward Reserve Auction shall apply price cascading such that the Forward Reserve Clearing Price for TMOR in a Reserve Zone is always less than or equal to the Forward Reserve Clearing Price for TMNSR in that Reserve Zone. If there is insufficient supply to meet the Forward Reserve requirements for a Reserve Zone, the Forward Reserve Clearing Price for that Reserve Zone will be set to the Forward Reserve Offer Cap.

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

Market Participants with cleared Forward Reserve Auction Offers will receive a Forward Reserve Obligation for each Reserve Zone, as applicable, that is equal to the amount of Forward Reserve megawatts cleared for that Market Participant adjusted for internal bilateral transactions that transfer Forward Reserve Obligations.

(a) Within five business days after the close of the Forward Reserve Auctions, the ISO shall post Forward Reserve Clearing Prices and Forward Reserve Obligations, which shall be final as posted, not subject to correction or other adjustment, and used for the purposes of settlement, except as provided in subsections (c) and (d). The permissibility of correction of errors in sections of Market Rule 1 relating to settlement and billing processes shall not apply to Forward Reserve Clearing Prices and Forward Reserve Obligations deemed final pursuant to this Section III.9.4.1.

(b) Before posting the final Forward Reserve Clearing Prices and Forward Reserve Obligations, the ISO shall make a good faith effort when clearing those markets to discover and correct any errors that may occur due to database, software or similar errors of the ISO or its systems before publishing the final prices awarded.

(c) If the ISO determines based on reasonable belief that there may be one or more errors in the final Forward Reserve Clearing Prices and Forward Reserve Obligations or if no Forward Reserve Clearing Prices and Forward Reserve Obligations 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 11:59 p.m. of the third business day following the posting deadline specified in subsection (a), a notice that the Forward Reserve Clearing Prices and Forward Reserve Obligations are provisional and subject to correction or unavailable for initial publishing. The ISO shall confirm within three business days of posting a notice pursuant to this subsection whether there was an error in the Forward Reserve Clearing Prices and Forward Reserve Obligations and shall post a notice stating its findings.

(d) Within three business days after posting an initial notice pursuant to subsection (c); the ISO shall either: (1) publish final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations, or: (2) in the event that the ISO is unable to calculate and post final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations due to exigent circumstances not contemplated in this market rule, make an emergency filing with the Commission detailing the exigent circumstance which will not allow final Forward Reserve Clearing Prices and Forward Reserve Obligations to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

III.9.5 Forward Reserve Resources

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

(a) Prior to the close of the Re-Offer Period for each Operating Day of the Forward Reserve Procurement Period, Market Participants must convert their Forward Reserve Obligations into Resource-specific obligations by assigning Forward Reserve MWs to specific eligible Forward Reserve Resources, in accordance with procedures set forth in the ISO New England Manuals. The assignment of Forward Reserve MWs to a Forward Reserve Resource must be performed by the Lead Market Participant for the Resource.

(b) A Market Participant with a Forward Reserve Obligation must have an Ownership Share in a Forward Reserve Resource that is a Generator Asset or a Dispatchable Asset Related Demand, or be the Lead Market Participant of a Forward Reserve Resource that is a Demand Response Resource, in order to assign Forward Reserve MWs to that Forward Reserve Resource to fulfill that Market Participant's Forward Reserve Obligation. If more than one Market Participant has an Ownership Share in a Forward Reserve Resource, the Forward Reserve MWs assigned to that Resource will be allocated pro-rata to Market Participants by Ownership Share.

III.9.5.2 Forward Reserve Resource Eligibility Requirements.

(a) Forward Reserve Resources are Resources that have been assigned by Market Participants to meet their Forward Reserve Obligations. To be eligible as a Forward Reserve Resource, a Resource must satisfy the following criteria:

(i) If the Generator Asset is off-line, it must be a Fast Start Generator and have an audited CLAIM10 or CLAIM30 established pursuant to Section III.9.5.3;

(ii) If the Resource is a Demand Response Resource which has not been dispatched, it must be a Fast Start Demand Response Resource and have an audited CLAIM10 or CLAIM30 established pursuant to Section III.9.5.3;

(iii) If the Generator Asset or Dispatchable Asset Related Demand is expected to be on-line, or, for a Demand Response Resource, has been dispatched, during a Forward Reserve Delivery Period, it must be able to produce the energy or demand reduction equivalent to its assigned Forward Reserve Obligation within the timeframe of the assigned Forward Reserve Obligation when operating within its dispatch range;

(iv) Any portion of the Resource to which a Forward Reserve Obligation has been assigned that is without a Capacity Supply Obligation must not have been offered to support an External Transaction sale during the Operating Day for which it has been assigned;

(v) The Resource must be capable of receiving and responding to electronic Dispatch Instructions;

(vi) The Resource must follow Dispatch Instructions during the Operating Day. The Resource must meet the technical requirements associated with the provision of Operating Reserve as specified in ISO New England Operating Procedure No. 14;

(vii) The portion of the Resource that is assigned a Forward Reserve Obligation for any portion of an Operating Day must be eligible to provide Operating Reserve in accordance with the provisions of Section III.1.7.19;

(viii) The portion of the Resource to which a Forward Reserve Obligation has been assigned must be offered into the Real-Time Energy Market in accordance with the provisions of either Section III.13.6.1.1.2 or Section III.13.6.1.5.2.

(b) External Resources will be permitted to participate in the Forward Reserve Market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.9.5.3 Resource CLAIM10 and CLAIM30.

III.9.5.3.1 Calculating Resource CLAIM10 and CLAIM30.

1. The CLAIM10 or CLAIM30 of a Resource shall equal:
   (a) the maximum output or demand-reduction level reached, including the level reached during a CLAIM10 or CLAIM30 audit, measured at the 10 minute or 30 minute point from the Resource's receipt of an initial electronic startup Dispatch Instruction during the current Summer Capability Period or Winter Capability Period or the preceding Summer Capability Period or Winter Capability Period (as applicable to the current capability period), subject to the conditions in Section III.9.5.3.1.2 below;

   (b) multiplied by the Resource's then effective CLAIM10 or CLAIM30 performance factor established pursuant to Section III.9.5.3.3.

2. The value in Section III.9.5.3.1.1(a) is subject to the following additional conditions:
   (a) The value shall not include any dispatch in which the Resource becomes unavailable within 60 minutes following the receipt of the initial Dispatch Instruction;

   (b) If the maximum output or demand-reduction level reached, as measured at the 10 minute or 30 minute point from the initial Dispatch Instruction, is greater than the highest Desired Dispatch Point issued for the Resource for that 10 minute or 30 minute period, the value shall be capped at the highest Desired Dispatch Point.

3. A Resource's CLAIM10 shall be no greater than the Resource's CLAIM30.

4. The CLAIM10 or CLAIM30 of a Resource shall be calculated and distributed to the Market Participant weekly and shall become effective at 0001 of the Monday following the distribution.

5. The values described in Sections III.9.5.3.1(1)(a) and (b) shall not include any dispatch where:

   a) The Resource is dispatched at the request of the Market Participant or Designated Entity and the dispatch was not related to an Establish Claimed Capability Audit request made pursuant to Section III.1.5.1.2, a Seasonal DR Audit request made pursuant to Section III.1.5.1.3.1, or a CLAIM10 or CLAIM30 audit request made pursuant to Section III.9.5.3.2;

b) The prices associated with the Blocks to Economic Min for the Real-Time dispatch of the Resource are less than or equal to zero;

c) For Generator Assets, the ratio of (i) the sum of the applicable Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min used in the Real-Time dispatch of the Resource in the Operating Day to (ii) the maximum total hourly Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min submitted for the Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold value determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to (i) differences in cost between Gas Days, or (ii) a reduction in the cost of gas within the Operating Day reflected in the offers submitted for the Resource during the remainder of the Operating Day, then the Market Participant may request that the ISO evaluate whether the dispatch may be included; or

d) For Demand Response Resources, the ratio of (i) the sum of the applicable Interruption Cost and the demand reduction cost to Minimum Reduction used in the Real-Time dispatch of the Demand Response Resource in the Operating Day to (ii) the maximum total hourly Interruption Cost and demand reduction cost to Minimum Reduction submitted for the Demand Response Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to differences in cost between Gas Days, then the Market Participant may request that the ISO evaluate whether the dispatch may be included.

6. A Demand Response Resource's CLAIM10 and CLAIM30 on June 1, 2018 and October 1, 2018 shall be as follows:

a) On June 1, 2018 and October 1, 2018, the CLAIM10 of a Demand Response Resource shall equal zero.

b) On June 1, 2018, the CLAIM30 of a Demand Response Resource with one or more Demand Response Assets that were 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) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Summer Capability Period beginning June 1, 2017. Such a CLAIM30 shall remain valid until the earlier of: (i) July 2, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before June 27, 2018, its CLAIM30 shall be set to zero on July 2, 2018.

c) On October 1, 2018, the CLAIM30 of a Demand Response Resource with one or more Demand Response Assets that were 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) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Winter Capability Period beginning October 1, 2017. Such a CLAIM30 shall remain valid until the earlier of: (i) October 29, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before October 24, 2018, its CLAIM30 shall be set to zero on October 29, 2018.

III.9.5.3.2 CLAIM10 and CLAIM30 Audits.

(a) **General.** A Market Participant may request a CLAIM10 or CLAIM30 audit specifying the requested output or demand-reduction level that the Resource will attempt to reach in 10 or 30 minutes. A Market Participant may not request more than one audit per week for the same Resource, provided that, if the Resource fails to start, trips offline, or becomes unavailable to provide a demand reduction during the audit, then the Market Participant may request another audit in the same week. The ISO, at its sole discretion, may allow a Market Participant to request more than one audit per week for the same Resource if the Resource historically has multiple startup dispatches included in its CLAIM10 or CLAIM30 calculations per week. A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(b) **CLAIM10 and CLAIM30 Audit Procedures.** The ISO will initiate a CLAIM10 or CLAIM30 audit by issuing an electronic Dispatch Instruction without providing prior notice to the Market Participant. The ISO will normally perform the audit, at any time between 0800 and 2200 on a non-NERC-holiday weekday, within five Business Days of receipt of the audit request or will advise the Market Participant if it will be unable to initiate the audit during the five Business Day period. The Resource’s CLAIM10 or CLAIM30 audit value shall be the Resource’s output or demand-reduction level reached at the 10 minute or 30 minute point after the receipt of the initial startup Dispatch Instruction.

III.9.5.3.3 CLAIM10 and CLAIM30 Performance Factors.

A Resource's CLAIM10 or CLAIM30 performance factor shall be established based upon the 10 most recent ISO-issued initial electronic startup Dispatch Instructions as described below. Dispatches greater than three years old shall not be used for the performance factor calculation. Resource performance factors will be calculated on a weekly basis.

(a) A Resource's performance factor is calculated as:

$$performance\ factor = \frac{\sum_{n=1}^{10}\left(\frac{resource\ output\ or\ demand\ reduction\ at\ 10\ or\ 30\ minutes_n\ (MW)}{resource\ target\ value_n\ (MW)} * n\right)}{\sum_{n=1}^{10} n}$$

Where:

n is a value between 1 and 10, 1 representing the least recent dispatch signal, 10 representing the most recent dispatch signal;

the Resource output or demand reduction is measured at the 10 minute or 30 minute point from receipt of the initial startup Dispatch Instruction;

the Resource target value is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute or 30 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM10 or CLAIM30 or (iii) the Resource's Offered CLAIM10 or Offered CLAIM30.

(b) For purposes of the performance factor calculation, the following conditions apply:

(i) For each CLAIM10 or CLAIM30 audit, the Resource's target value shall be set to the Resource's output or demand reduction at 10 or 30 minutes.

(ii) In the event the Resource has not had 10 electronic startup dispatches within the last three years, the "n" term in the performance factor calculation will be based on the number of startup dispatches that took place in the last three years, with the most recent dispatch having a weight of 10 and with the weighting decreasing by 1 for each previous startup dispatch.

(iii) If a Resource's output or demand reduction at 10 or 30 minutes is greater than the Resource's target value, then the Resource target value shall be set to the Resource output at 10 or 30 minutes.

(iv) A dispatch shall not be utilized in the performance factor calculation if a Resource starts and subsequently performs a normal shut down or ceases its demand reduction, in response to a Dispatch Instruction to shut down or, for a Demand Response Resource, in response to a Dispatch Instruction to cease its demand reduction, within the 10 or 30 minute period following the initial electronic startup Dispatch Instruction.

(v) Resource output or demand reduction at 10 or 30 minutes shall equal zero if the Resource becomes unavailable for dispatch within the 60 minute period following the initial electronic startup Dispatch Instruction.

III.9.5.3.4 Performance Factor Cure.

In the event a Resource either (a) is unable to reach at least 60% of the Resource target level, as reflected in the Dispatch Instruction issued for the Resource, either five times in a row or seven out of 10 times, as a result of a chronic operational problem with the Resource or (b) undergoes a major overhaul scheduled and performed during a planned outage that was approved in the ISO's annual maintenance scheduling process or during a scheduled curtailment pursuant to Section III.8.3, a Market Participant may submit a restoration plan to the ISO to restore the Resource's CLAIM10 or CLAIM30 operational capability. Restoration plans submitted because of a Resource's inability to reach its target output or demand reduction shall indicate the specific nature of the problem, the steps to be taken to remedy the problem, and the timeline for completing the restoration. Restoration plans submitted for a major overhaul shall explain the actions taken during the planned outage or scheduled curtailment that would result in the increase of the Resource's CLAIM10 or CLAIM30. The ISO shall accept restoration plans that, upon review, indicate a reasonable likelihood of success in remedying the identified problem or, for a major overhaul, increasing the Resource's CLAIM10 or CLAIM30. Upon completion of the restoration, the Market Participant shall request a CLAIM10 or CLAIM30 audit of the Resource, using the procedures in Section III.9.5.3.2. Following the audit, the Resource's Performance Factor shall be set to 1.0, with all dispatches prior to the audit removed from the performance factor calculation.

III.9.6 Delivery of Reserve.

III.9.6.1 Dispatch and Energy Bidding of Reserve.

Forward Reserve shall be delivered by Forward Reserve Resources that are Generator Assets or Dispatchable Asset Related Demand for an hour by offering the capability into the Real-Time Energy Market by submitting Supply Offers and Demand Bids no later than 30 minutes prior to the start of the operating hour at or above the Forward Reserve Threshold Price for the Operating Day. Day-Ahead Energy Market Supply Offers and Demand Bids for Resources to which Forward Reserve Obligations have been assigned will be used in the Real-Time Energy Market for the associated Operating Day, even if the Supply Offers do not clear the Day-Ahead Energy Market, unless superseded by a more recent Supply Offer or Demand Bid submitted no later than 30 minutes prior to the start of the operating hour. A Market Participant is not required to submit a Supply Offer or Demand Bid into the Day-Ahead Energy Market for a Resource without a Capacity Supply Obligation in order for the Resource to be eligible to be a Forward Reserve Resource. The Forward Reserve Threshold Prices shall be set in accordance with the ISO New England Manuals so that Forward Reserve Resource capability has (a) a low probability of being dispatched for energy and (b) a high probability of being held for reserve purposes.

Forward Reserve shall be delivered by Forward Reserve Resources that are Demand Response Resources for an hour by offering the capability into the Real-Time Energy Market by submitting Demand Reduction Offers no later than the close of the Re-Offer Period at or above the Forward Reserve Threshold Price for the Operating Day.

Forward Reserve Resources are scheduled and operated in accordance with Section III.1 of Market Rule 1; no distinction is made due to their status as Forward Reserve Resources. Forward Reserve Resources are eligible to set the Locational Marginal Price in accordance with Section III.2 of Market Rule 1.

III.9.6.2 Forward Reserve Threshold Prices.

The formula for determining the Forward Reserve Threshold Prices shall be fixed for the duration of the Forward Reserve Procurement Period. The ISO will reevaluate the Forward Reserve Threshold Price level for successive Forward Reserve Auctions on the basis of experience, expected operating conditions and other relevant information.

Forward Reserve Threshold Price: is calculated as the Forward Reserve Heat Rate multiplied by the daily Forward Reserve Fuel Index.

Forward Reserve Heat Rate: shall be fixed for the duration of the Forward Reserve Procurement Period and announced in the announcement for the Forward Reserve Auction. New Forward Reserve Heat Rates shall be specified for successive auctions, and shall be calculated as follows:

(a) For each of the five most recently completed Summer Capability Periods or Winter Capability Periods (as applicable to the Forward Reserve Procurement Period), for each on-peak hour, the ISO shall calculate an implied heat rate, expressed in Btu/kWh, by dividing the hour's Hub Price by the lower of the applicable natural gas or heating oil price index.

(b) All resulting hourly implied heat rates above 45,000 Btu/kWh shall be excluded, and the remaining values shall be listed in order from high to low.

(c) The Forward Reserve Heat Rate for the Forward Reserve Procurement Period shall be the lesser of: (i) the heat rate that occurs at the 97.5th percentile of the list described in subsection (b) above; or (ii) 21,999 Btu/kWh.

Forward Reserve Fuel Index: is a daily fuel index, or combination of daily indices, applicable to the New England Control Area and specified in the announcement of the Forward Reserve Auction.

III.9.6.3 Monitoring of Forward Reserve Resources.

In accordance with Section III.A.13.4, the Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Participant in accordance with Section III.A.3. 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.

III.9.6.4 Forward Reserve Qualifying Megawatts.

(a) Generator Assets and Dispatchable Asset Related Demands – Qualifying megawatts for Generator Assets and Dispatchable Asset Related Demands are calculated separately on an hourly basis for Forward Reserve Resources supplying Forward Reserve from an off-line state and Forward Reserve Resources supplying Forward Reserve from an on-line state as follows:

Off-line qualifying megawatts. Off-line qualifying megawatts are the amount of a Generator Asset's capability equal to or below the Economic Maximum Limit for an off-line Forward Reserve Resource offered at or above the Forward Reserve Threshold Price. The Generator Asset must satisfy this requirement in the Real-Time Energy Market. In the case of off-line Forward Reserve Resources, the calculation for Forward Reserve Qualifying Megawatts shall include both the energy Supply Offer and a pro-rated amount of Start-Up Fees and No-Load Fees as defined below. The off-line qualifying megawatts of a Dispatchable Asset Related Demand are zero.

An off-line Forward Reserve Resource must offer its capability so that the following holds:

$$\frac{StartUp}{EcoMax \times 1\ hour} + \frac{NoLoad}{EcoMax} + Energy\ Offer_i \geq ForwardReserveThresholdPrice$$

where:

StartUp = cold Start-Up Fee.
NoLoad = No-Load Fee.
$EnergyOffer_i$ = the Energy offer price for
Energy offer block $_i$.
EcoMax = Economic Maximum Limit.

On-line qualifying megawatts: is the capability that is less than or equal to the Economic Maximum Limit and above the Economic Minimum Limit that is offered at or above the applicable Forward Reserve Threshold Price by an on-line Generator Asset or, is the capability that is less than or equal to the Maximum Consumption Limit and greater than the Minimum Consumption Limit offered at or above the applicable Forward Reserve Threshold Price for a Dispatchable Asset Related Demand. The Forward Reserve Resource must satisfy this requirement in the Real-Time Energy Market. For an on-line Generator Asset that has been assigned to meet a Forward Reserve Obligation and has not cleared in the Day-Ahead Energy Market and is operating in a delivery hour as the result of an ISO commitment for VAR or local second contingency protection, the on-line qualifying megawatts shall be zero.

(b) **Demand Response Resources** – Qualifying megawatts for Demand Response Resources supplying Forward Reserve are calculated separately on an hourly basis for Demand Response Resources that have not been dispatched and Demand Response Resources that have been dispatched as follows:

Qualifying megawatts for a Demand Response Resource that has not been dispatched: is the amount of capability equal to or below the Maximum Reduction for the Demand Response Resource offered at or above the Forward Reserve Threshold Price. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. In the case of Demand Response Resources that have not been dispatched, the calculation for Forward Reserve Qualifying Megawatts shall include both the Demand Reduction Offer price and a pro-rated amount of the Interruption Cost as defined below.

A Demand Response Resource that has not been dispatched must offer its capability so that the following holds:

$$\frac{Interruption\ Cost}{MaxRed} + Energy\ Offer_i \geq Forward\ Reserve\ Threshold\ Price$$

where:

Interruption Cost = Interruption Cost.
$EnergyOffer_i$ = Demand Reduction Offer price for Energy offer block $_i$.
Max Red = Maximum Reduction x 1 hour.

Qualifying megawatts for a Demand Response Resource which has been dispatched: is the capability that is less than or equal to the Maximum Reduction and greater than the Minimum Reduction that is offered at or above the applicable Forward Reserve Threshold Price for the Demand Response Resource. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. For a Demand Response Resource which has been dispatched, has been assigned to meet a Forward Reserve Obligation, has not cleared in the Day-Ahead Energy Market, and is operating in a delivery hour as the result of an ISO commitment for local second contingency protection, the qualifying megawatts shall be zero.

III.9.6.5 Delivery Accounting.

Forward Reserve Delivered Megawatts are the quantity of Forward Reserve delivered in each hour of the Real-Time Energy Market to each Reserve Zone and is calculated as follows:

(a) Forward Reserve Delivered Megawatts for an off-line Generator Asset are calculated in megawatts for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount, in MW, of Forward Reserve that the off-line Generator Asset can provide, based upon CLAIM10 and CLAIM30 provided in the Generator Asset's Real-Time Supply Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(b) <u>Forward Reserve Delivered Megawatts for an on-line Generator Asset</u> are calculated in megawatts for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramp rate of the on-line Generator Asset, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(c) <u>Forward Reserve Delivered Megawatts for an on-line Dispatchable Asset Related Demand</u> are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramp rate of the Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2),

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(d) A Forward Reserve Resource's hourly Forward Reserve Delivered Megawatts for each Reserve Zone is calculated as the sum of the Market Participant's Resource specific hourly Forward Reserve Delivered Megawatts for each Reserve Zone.

(e) Resource specific Forward Reserve Delivered Megawatts for TMNSR within a Reserve Zone will be applied first to a Market Participant's higher value Forward Reserve Obligation for TMNSR in that Reserve Zone. Any surplus Forward Reserve Delivered Megawatts for TMNSR in that Reserve Zone will be applied to meet the Market Participant's Forward Reserve Obligation for TMOR in that Reserve Zone. Forward Reserve Delivered Megawatts remaining within that Reserve Zone after the Market Participant's Forward Reserve Obligation for that Reserve Zone have been met is available to be applied to the Market Participant's Forward Reserve Obligations in other Reserve Zones provided that the Forward Reserve Delivered Megawatts can be delivered to the other Reserve Zones.

(f) Forward Reserve Delivered Megawatts for a Demand Response Resource which has not been dispatched are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount of Forward Reserve that the Resource can provide, based upon CLAIM10 and CLAIM30 provided in the Demand Response Resource's Demand Reduction Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (energy at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(g) Forward Reserve Delivered Megawatts for a Demand Response Resource which has been dispatched are calculated for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute Demand Response Resource Ramp Rate of that Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(h) In determining Forward Reserve Delivered Megawatts for Demand Response Resources the portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be increased by average avoided peak distribution losses, limited as described below.

(i) The ISO will assume that Demand Response Resources first reduce their net load from the electricity system before providing additional Net Supply.

(ii) The portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be the lesser of: (1) Forward Reserve Delivered Megawatts and (2) the amount of load that the Demand Response Resource can reduce from the electric system based on the net load of its constituent Demand Response Assets.

(iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with Net Supply will be capped at the remaining Net Supply Capability of the Demand Response Resource.

III.9.7 Consequences of Delivery Failure.

III.9.7.1 Real-Time Failure-to-Reserve.

A Real-Time Forward Reserve Failure-to-Reserve 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.

(a) Forward Reserve Failure-to-Reserve Megawatts:

(i) A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMNSR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(1) Market Participant Forward Reserve Obligation for TMNSR for that Reserve Zone minus the Market Participant's Forward Reserve Delivered Megawatts for TMNSR for that Reserve Zone; and

(2) Zero.

(ii) A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMOR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(1) Market Participant Forward Reserve Obligation for TMOR for that Reserve Zone minus Market Participant's Forward Reserve Delivered Megawatts for TMOR for that Reserve Zone; and

(2) Zero.

(b) Forward Reserve Failure-to-Reserve Penalties: A Market Participant's Forward Reserve Failure-to-Reserve Penalty for a Reserve Zone in an hour is defined as:

(i) Forward Reserve Failure-to-Reserve Penalty for TMNSR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Reserve Penalty for TMOR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Reserve Penalty Rate (calculated for each Forward Reserve product and for each Reserve Zone) = maximum of (1.5 multiplied by the Forward Reserve Payment Rate for the Forward Reserve product, the applicable Real-Time Reserve Clearing Price for the Forward Reserve product in the Reserve Zone minus the Forward Reserve Payment Rate for the Forward Reserve product)

III.9.7.2 Failure-to-Activate Penalties.

Market Participants are required to pay a Forward Reserve Failure-to-Activate Penalty for each Forward Reserve Resource that fails to activate its Forward Reserve capability. For Forward Reserve Resources:

- providing TMNSR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction as part of the real-time contingency dispatch algorithm, or;
- providing TMOR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction when the ten-minute reserve requirement is binding or violated in an approved UDS case.

If a Market Participant's Forward Reserve Resource fails to activate Forward Reserve, which determination shall be made in accordance with subsection (a), that Market Participant shall be required to pay a Forward Reserve Failure-to-Activate Penalty associated with that Resource pursuant to subsection (b):

(a) **Forward Reserve Failure-to-Activate Megawatts**:

(i) A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMNSR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(1) Maximum of Forward Reserve Delivered Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

(2) Maximum of Target Activation Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMNSR from off-line Forward Reserve Resources or Demand Response Resources that are not dispatched, which are subsequently dispatched as part of the real-time contingency dispatch algorithm is the lesser of: (i) the minimum electronic Desired

Dispatch Point sent to the Resource during the 10 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater, (ii) the Resource's CLAIM10, and (iii) the Resource's Offered CLAIM10.

Target Activation Megawatts for TMNSR from on-line Forward Reserve Resources or Demand Response Resources that have been dispatched is as follows:

1. For Generator Assets, the lesser of: (i) the Resource's Manual Response Rate times 10 minutes, (ii) the Resource's Economic Maximum Limit minus the Resource's initial output at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource's initial output at activation.
2. For Storage DARDs, the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 10 minute period.
3. For DARDs that are not Storage DARDs, the lesser of: (i) the Resource's Manual Response Rate times 10 minutes, (ii) Resource's initial consumption at activation minus the Resource's Minimum Consumption Limit, and (iii) the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 10 minute period.
4. For Demand Response Resources, the lesser of: (i) the Resource's Demand Response Resource Ramp Rate times 10 minutes, (ii) the Resource's Maximum Reduction minus the Resource's initial demand reduction at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource's initial demand reduction at activation.

The actual amount of TMNSR energy delivered during activation is measured at the 10 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMNSR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

(ii) A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMOR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(1) Maximum of Forward Reserve Delivered Megawatts for TMOR plus Forward Reserve Delivered Megawatts for TMNSR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

(2) Maximum of Target Activation Megawatts for TMOR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMOR from off-line Forward Reserve Resources or Demand Response Resources that are not dispatched is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM30, or; (iii) the Resource's Offered CLAIM30.

Target Activation Megawatts for TMOR from on-line Forward Reserve Resources or Demand Response Resources that have been dispatched is as follows:

1. For Generator Assets, the lesser of: (i) the Resource's Manual Response Rate times 30 minutes, (ii) the Resource's Economic Maximum Limit minus the Resource's initial output at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial output at activation.
2. For Storage DARDs, the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 30 minute period.
3. For DARDs that are not Storage DARDs, the lesser of: (i) the Resource's Manual Response Rate times 30 minutes, (ii) Resource's initial consumption at activation minus the Resource's Minimum Consumption Limit, and (iii) the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 30 minute period.

4. For Demand Response Resources, the lesser of: (i) the Resource's Demand Response Resource Ramp Rate times 30 minutes, (ii) the Resource's Maximum Reduction minus the Resource's initial demand reduction at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial demand reduction at activation.

The actual amount of TMOR energy delivered during activation is measured at the 30 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMOR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

(iii) In determining the Target Activation Megawatts for Demand Response Resources, the portion of the Target Activation Megawatts not associated with Net Supply shall be increased by average avoided peak distribution losses. The portion of the Target Activation Megawatts not associated with Net Supply shall be calculated as the greater of: (1) the Target Activation Megawatts minus the amount of Net Supply that the Demand Response Resource produced during activation or (2) zero.

A Forward Reserve Resource that is a Fast Start Generator that fails to activate Forward Reserve through a failure to start, or a Forward Reserve Resource that is a Fast Start Demand Response Resource that fails to activate Forward Reserve through a failure to provide a demand reduction, shall have its Forward Reserve Delivered Megawatts set equal to zero in each subsequent hour in the applicable Forward Reserve Delivery Period until such time that the Market Participant notifies the ISO that the Forward Reserve Resource is capable of providing the Forward Reserve Delivered Megawatts.

(b) **Forward Reserve Failure-to-Activate Penalties:**

A Market Participant's Forward Reserve Failure-to-Activate Penalty for a Resource in an hour is defined as:

(i) Forward Reserve Failure-to-Activate Penalty for TMNSR = The sum of the Forward Reserve Payment Rate for TMNSR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Activate Penalty for TMOR = The sum of the Forward Reserve Payment Rate for TMOR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Activate Penalty Rate = Maximum of 2.25 multiplied by the Forward Reserve Payment Rate, or the applicable nodal LMP.

III.9.7.3 Known Performance Limitations.

The ISO may have reason to believe that a particular Forward Reserve Resource is frequently receiving, or may frequently receive, Forward Reserve payments for a portion or all of its capability that is not capable of activating the Forward Reserve Assigned Megawatts for TMNSR or the Forward Reserve Assigned Megawatts for TMOR. When the ISO believes there is such a limited Forward Reserve Resource, the ISO shall contact and confer with the affected Market Participant before taking any action.

(a) The ISO will, whenever practicable, contact the affected Market Participant of the Forward Reserve Resource to request an explanation of the relevant resource Offer Data;

(b) If the explanation, if available, considered together with other information available to the ISO, indicates to the satisfaction of the ISO that the questioned Forward Reserve payments are consistent with Forward Reserve Resource capabilities, no further action will be taken; and

(c) If no agreement is reached, or an acceptable explanation is not provided, the Market Participant may request a Resource performance audit. If the Forward Reserve Resource fails the performance audit or the Market Participant refuses to request a Resource performance audit, the ISO may take remedial action. Remedial actions may include, but are not limited to: (i) redeclaration, by the ISO, of any relevant operational Offer Data parameter, or (ii) removing the Resource or the relevant portion of the Resource's capability to provide Forward Reserve on a going-forward basis.

III.9.8 Forward Reserve Credits.

Payment for Forward Reserve is based upon a Market Participant's Final Forward Reserve Obligation and the applicable Forward Reserve Clearing Prices. The ISO shall calculate these credits on an hourly basis for each Reserve Zone as follows:

(a) Final Forward Reserve Obligations for TMNSR and TMOR for each Market Participant are calculated for each Reserve Zone for each hour as follows:

(i) Final Forward Reserve Obligation = minimum [Forward Reserve Obligation, Forward Reserve Delivered Megawatts]

(b) $FRACP_{Zone}$ is defined as the Forward Reserve Clearing Price for the relevant Reserve Zone, for TMNSR or TMOR, respectively;

(c) Market Participant Forward Reserve Credit for TMNSR=Final Forward Reserve Obligation for TMNSR multiplied by the applicable hourly Forward Reserve Payment Rate for TMNSR;

where,

the hourly Forward Reserve Payment Rate for TMNSR is equal to:

applicable monthly $FRACP_{Zone}$ for TMNSR divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

(d) Market Participant Forward Reserve Credit for TMOR = Final Forward Reserve Obligation for TMOR multiplied by the applicable hourly Forward Reserve Payment Rate for TMOR;

where,

the hourly Forward Reserve Payment Rate for TMOR is equal to:

applicable monthly $FRACP_{Zone}$ for TMOR divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

III.9.9 Forward Reserve Charges.

Forward Reserve Charges are allocated to each Market Participant in two steps. The first step allocates the Forward Reserve Credits associated with the procurement of reserves to meet the Forward Reserve requirement for the system. The second step, if necessary, allocates any remaining Forward Reserve Credits.

III.9.9.1 Forward Reserve Credits Associated with System Reserve Requirement.
The portion of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is determined by simulating a Forward Reserve Auction using all submitted Forward Reserve Auction Offers to meet only the Forward Reserve Market minimum requirements for the New England Control Area pursuant to Section III.9.2.1. The simulated Forward Reserve Auction will clear offers pursuant to the methodology set forth in Section III.9.4 to calculate TMNSR and TMOR proxy system clearing prices. The TMNSR and TMOR proxy system clearing prices will reflect the cost to serve the next increment of reserve above the Forward Reserve Market minimum requirement for the New England Control Area.

For each hour, the total amount of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is calculated as the lesser of:

(i) The TMNSR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the TMNSR proxy system clearing price, plus the TMOR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the TMOR proxy system clearing price and divided by the number of hours in the month associated with the Forward Reserve Delivery Period, or

(ii) Total Forward Reserve Credits for the New England Control Area as calculated pursuant to Section III.9.8.

III.9.9.2 Adjusting Forward Reserve Credits for System Requirement.
For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is reduced by:

(i) Any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in the Rest of System or in a Load Zone that is ineligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, and

(ii) A prorated amount of any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in a Load Zone that is eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.3 Allocating Forward Reserve Credits for System Requirements.

For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirements for the system as calculated pursuant to Section III.9.9.1, is reduced by any penalties calculated pursuant to Section III.9.9.2, and allocated on a pro rata basis using each Market Participant's share of Real-Time Load Obligation in each Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Reserve Quantity For Settlement associated with Dispatchable Asset Related Demands within that Load Zone.

III.9.9.4 Allocating Remaining Forward Reserve Credits.

For each hour, any Forward Reserve Credits not allocated pursuant to Section III.9.9.3 are allocated on a pro rata basis to each Market Participant's share of Real-Time Load Obligation in a Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Reserve Quantity For Settlement associated with Dispatchable Asset Related Demands within that Load Zone) that meets the criteria in Section III.9.9.4.1. The allocation for each Load Zone is based on the ratio of the Forward Reserve Credits cleared in the Respective Reserve Zone for the Forward Reserve Credits cleared in all Reserve Zones that meet the criteria in Section III.9.9.4.1, and is reduced by:

(i) A prorated amount of any Forward Reserve Failure-to-Reserve Penalties or Forward Reserve Failure-to-Activate Penalties that occur in a Load Zone eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of the total Forward Reserve Credits less any Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.4.1 Allocation Criteria for Remaining Forward Reserve Credits.

If the following criteria are met, then a Market Participant with Real-Time Load Obligation in a Load Zone is eligible to receive any remaining Forward Reserve Credits not allocated pursuant to Section III.9.9.3.

(i) The Load Zone is encompassed in whole or in part in a Reserve Zone with a zonal Forward Reserve requirement greater than zero, and

(ii) The Forward Reserve Clearing Price of a Reserve Zone is higher than the Forward Reserve Clearing Price of the Rest of System.

III.10 Settlement for Real-Time Reserves

For purposes of this Section III.10, unless otherwise expressly stated, the settlement interval is five minutes. 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.

III.10.1 Reserve Quantity For Settlement

Each Resource receiving a Real-Time Reserve Designation pursuant to Section III.1.7.19 shall receive, for each settlement interval, a Reserve Quantity For Settlement. The Reserve Quantity For Settlement 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. The Reserve Quantity For Settlement values will equal the corresponding Real-Time Reserve Designation values, adjusted downward after the fact to account for actual reserve capability based on Metered Quantity For Settlement.

III.10.2 Real-Time Reserve Credits

For each Market Participant for each hour, the ISO will determine a credit for provision of Operating Reserve in Real-Time. Demand Response Resource credits will be limited as described in Section III.9.6.5(h).

(a) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMSR for an hour shall be equal to the sum of the Real-Time Reserve Credit for TMSR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMSR for an interval is calculated by multiplying the Market Participant's Resource specific Reserve Quantity For Settlement for TMSR (where any portion of Reserve Quantity For Settlement provided by a Demand Response Resource, other than MWs associated with Net Supply, is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMSR for the interval. The Real-Time Reserve Credit for TMSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific hourly Real-Time Reserve Credits for TMSR in that Load Zone.

(b) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMNSR shall be equal to the sum of the Real-Time Reserve Credit for TMNSR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMNSR for an interval is calculated by multiplying the Market

Participant's Resource specific Reserve Quantity For Settlement for TMNSR (where any portion of Reserve Quantity For Settlement provided by a Demand Response Resource, other than MWs associated with Net Supply, is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMNSR for the interval. The Real-Time Reserve Credit for TMNSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific hourly Real-Time Reserve Credits for TMNSR in that Load Zone.

(c) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMOR shall be equal to the sum of the Real-Time Reserve Credit for TMOR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMOR for an interval is calculated by multiplying the Market Participant's Resource specific Reserve Quantity For Settlement for TMOR (where any portion of Reserve Quantity For Settlement provided by a Demand Response Resource, other than MWs associated with Net Supply, is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMOR for the interval. The Real-Time Reserve Credit for TMOR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMOR in that Load Zone.

III.10.3 Real-Time Reserve Charges.

(a) For each hour, the ISO will allocate the sum of the Real-Time Reserve Credits and Forward Reserve Obligation Charges for each Load Zone, calculated separately for TMSR, TMNSR and TMOR, to each Market Participant as follows:

Real-Time Reserve $\text{Charge}_{k,i}$ = [Reserve Charge Allocation $\text{MW}_{k,i}$] x [RT_CHRG_RT_i]

Where:

Real-Time Reserve $\text{Charge}_{k,i}$, is Market Participant *k's* Real-Time Reserve Charge for Load Zone *i* for all Real-Time reserve services and Forward Reserve Obligation Charges;

Reserve Charge Allocation MW = Market Participant *k's* Real Time Load Obligation in Load Zone *i* adjusted for the Reserve Quantity For Settlement MWs of Market Participant *k's* Dispatchable Asset Related Demand MWs in Load Zone *i*.

$RT\_CHRG\_RT_i$ = [IRT_SUP_PMNT]/RT_P_WTD_LD_OB] x
[RT_P_RATIO] for TMSR, TMNSR, or TMOR, as applicable.

RT_P_WTD_LD_OB = ∑[Reserve Charge Allocation MW_{si}] x
[P_RATIO_i] for TMSR, TMNSR or TMOR, as applicable;

[RT_SUP_PMNT] = The total over all Load Zones of Real-Time Reserve Credits for TMSR, TMNSR or TMOR, plus the total over all Load Zones of the Forward Reserve Obligation Charges for TMNSR or TMOR, as applicable;

$RT\_P\_RATIO_i$ is the ratio of the Real Time Reserve Clearing Price in Load Zone i for TMSR, TMNSR or TMOR, as applicable, to the Real -Time Reserve Clearing Price in the Reference Zone for TMSR, TMNSR or TMOR, as applicable. To the extent that a Load Zone contains more than one Reserve Zone, that Load Zone's Real-Time Reserve Clearing Price for TMSR, TMNSR or TMOR shall be the Reserve Quantity For Settlement weighted average of the Reserve Zone Real-Time Reserve Clearing Prices in that Load Zone for TMSR, TMNSR or TMOR, as applicable;

The Reference Load Zone is the Load Zone with the minimum, non-zero Real-Time Reserve Clearing Price for TMSR, TMNSR or TMOR, as applicable.

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 Load Zone from which the External Transaction is exporting for the purpose of calculating Real-Time Reserve Charges. 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.

III.10.4 Forward Reserve Obligation Charges.

For each Market Participant with a Forward Reserve Obligation, the ISO will determine a Forward Reserve Obligation Charge for each settlement interval such that a Market Participant will not receive compensation for Real-Time Operating Reserve MWs provided to satisfy a Forward Reserve Obligation.

For purposes of the calculations in this Section III.10.4: (1) when a Market Participant assigns a Forward Reserve Resource in one Reserve Zone to meet a Forward Reserve Obligation in another Reserve Zone, any Forward Reserve Obligation Charge megawatts associated with that Resource are allocated to the Reserve Zone in which the Market Participant holds the Forward Reserve Obligation; and (2) if a Market Participant satisfies a Forward Reserve Obligation for TMOR with Forward Reserve Delivered MW of TMNSR, the Forward Reserve Obligation Charge megawatts are allocated to the Market Participant's Forward Reserve Obligation for TMOR.

III.10.4.1 Forward Reserve Obligation Charge Megawatts for Forward Reserve Resources.

The Forward Reserve Obligation Charge megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Forward Reserve Resource are equal to the lesser of the Forward Reserve Delivered MW or Reserve Quantity For Settlement (where any portion of Reserve Quantity For Settlement provided by a Demand Response Resource, other than MWs associated with Net Supply, is increased by average avoided peak distribution losses).

III.10.4.2 Forward Reserve Obligation Charge Megawatts.

The Forward Reserve Obligation Charge megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Market Participant is equal to the lesser of the sum of Forward Reserve Obligation Charge megawatts for all the Reserve Resources assigned by the Market Participant, or the Final Forward Reserve Obligation

III.10.4.3 Forward Reserve Obligation Charge.

The Forward Reserve Obligation Charge will be calculated as follows:

(a) A Market Participant's Forward Reserve Obligation Charge for TMNSR in each Reserve Zone shall be equal to the Market Participant's Forward Reserve Obligation Charge megawatts for TMNSR in that Reserve Zone multiplied by the Real-Time Reserve Clearing Price for TMNSR in that Reserve Zone.

(b) A Market Participant's Forward Reserve Obligation Charge for TMOR in each Reserve Zone shall be equal to the Market Participant's Forward Reserve Obligation Charge megawatts for TMOR in that Reserve Zone multiplied by the Real-Time Reserve Clearing Price for TMOR in that Reserve Zone.

III.11 Gap RFPs For Reliability Purposes

III.11.1 Request For Proposals for Load Response and Supplemental Generation Resources for Reliability Purposes.

(a) Should the ISO determine that a region may have potential critical near-term power supply reliability problems for which no Market Participant has proposed or committed to implement a viable solution (from a timeliness or financial standpoint), the ISO may, after consultation with the Reliability Committee, issue a request for proposals (Gap RFP). The Gap RFP will solicit load response and other supplemental supply to maintain near-term reliability in the identified region. For any Gap RFP issued after December 31, 2003, the ISO shall file such Gap RFP with the Commission for approval at least 60 days prior to its issuance. The filing shall include proposed Gap RFP terms and conditions and shall explain why market incentives were unable to solicit a market response in the absence of the Gap RFP.

(b) The ISO may enter into contracts awarded pursuant to a competitive Gap RFP process. Bidders that are awarded contracts through the Gap RFP process shall file those contracts with the Commission for approval of the rates to be charged thereunder to the extent that such contracts are for services that are jurisdictional to the Commission. All other contracts entered into pursuant to a Gap RFP shall be filed with the Commission for informational purposes.

(c) The costs for load response and other supply selected through any Gap RFP issued by the ISO pursuant to this Section III.11.1 shall be allocated and charged pro rata to Market Participants and Non-Market Participants with Regional Network Load in proportion to the sum of their Regional Network Load during that month within the affected Reliability Region.

III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

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

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

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

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

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

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

Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction.

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

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

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

III.12.2.1.1. Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

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

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

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

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

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

In which:

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

Proxy Units Adjustment	=	MW of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1 days/year.

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

III.12.2.1.2. Transmission Security Analysis Requirement.

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

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

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

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

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

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

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

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

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

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

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

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

$$\text{Maximum Capacity Limit}_{Y} = ICR - LRA_{RestofNewEngland}$$

In which:

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

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

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

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

III.12.3 Consultation and Filing of Capacity Requirements.
At least two months prior to filing the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with

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

III.12.4. Capacity Zones.

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

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

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

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

III.12.4A. Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location of Active Demand Capacity Resources. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction, and those Dispatch Zones shall remain in place through the end of the Capacity Commitment Period for which they were established. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.12.5. Transmission Interface Limits.

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

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

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

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

(i) all existing resources, along with any associated interconnection facilities and/or Elective Transmission Upgrades that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Sections III.13.2.5.2.5.3 and III.13.2.8.3;

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

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

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

III.12.6.1. Process for Establishing the Network Model.

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

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

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

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

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

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

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

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

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

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

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

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

III.12.6.3. Evaluation Criteria.

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

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

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

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

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

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

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

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

III.12.6.4. Transmission Solutions Selected Through the Competitive Transmission Process.

For a transmission solution, which may consist of single or multiple proposals, selected through the competitive transmission process pursuant to Sections 4.3, 4A, 16 or 17 of Attachment K, such transmission solution, or relevant portion thereof, shall be considered in-service on the in-service date provided in the executed Selected Qualified Transmission Project Sponsor Agreement(s). The ISO shall use the in-service date in the executed Selected Qualified Transmission Project Sponsor Agreement(s) to determine whether to include the transmission solution, or relevant portion thereof, in the network model for the relevant Capacity Commitment Period. In the event that the selected transmission solution includes an upgrade(s) located on a PTO's existing transmission system where the Selected Qualified Transmission Project Sponsor is not the PTO for the existing system element(s) being upgraded, the process for establishing the in-service date and determining whether to include the upgrade(s) on the existing transmission system, or relevant portion thereof, in the network model for the Capacity Commitment Period shall be as described in Section III.12.6.1.

III.12.7. Resource Modeling Assumptions.

III.12.7.1. Proxy Units.

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

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

III.12.7.2. Capacity.

The resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall include:

(a) all Existing Generating Capacity Resources,

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

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

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

(e) all Existing Distributed Energy Capacity Resources,

but shall exclude:

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

(g) capacity de-listed or retired as a result of Permanent De-List Bids, Retirement De-List Bids, or substitution auction demand bids that cleared in previous Forward Capacity Auctions, and

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

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

III.12.7.2.1. [Reserved.]

III.12.7.3. Resource Availability.

The Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated taking resource availability into account and shall be determined as follows:

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

(b) [Reserved.]

For resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that do not have sufficient data to calculate an availability metric as defined in subsection (a) above, class average data for similar resource types shall be used.

For existing Active Demand Capacity Resources:

Historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

For Distributed Energy Capacity Resources:

For each Distributed Energy Capacity Resource, the availability metric for each underlying technology type will be applied in the same manner as it would be applied if the Distributed Energy Capacity Resource were qualified as a generator or demand response resource.

III.12.7.4. Load and Capacity Relief.

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

(a) **Implement voltage reduction**. The MW value of the load relief shall be equal to 1% of (the 90/10 forecasted seasonal net peak loads minus all Existing Demand Capacity Resources).

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

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

III.12.8. Load Modeling Assumptions.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias. To ensure that Demand Response Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources are not reflected as reductions in the load forecast, the ISO shall reflect them in historical loads as specified below.

(a) The ISO shall add back into historical loads the metered MW demand reduction of Demand Response Resources dispatched by the ISO.

(b) [Reserved.]

(c) [Reserved.]

(d) The ISO shall add back into historical loads summer and winter MW values to account for On-Peak Demand Resources and Seasonal Peak Demand Resources as follows:

The ISO shall develop a trend line between (i) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (June 1, 2006) and (ii) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for June 1 of the associated Capacity Commitment Period. To determine the summer MW values to be added back into historical loads, the ISO shall apply the resulting trend to the summer months (April through November) in all the historical years covered by the trend line.

The ISO shall develop a trend line between (i) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (December 1, 2006) and (ii) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for December 1 of the associated Capacity Commitment Period. To determine the winter MW values to be added back into historical loads, the ISO shall apply the resulting trend to the winter months (December through March) in all the historical years covered by the trend line.

The ISO shall make adjustments to forecasted loads to account for any differences between the most recently available MW values reflective of the Capacity Supply Obligations that On-Peak Demand Resources and Seasonal Peak Demand Resources acquired in each of the annual reconfiguration auctions and the MW values reflective of the Capacity Supply Obligations that those resources acquired in the corresponding Forward Capacity Auctions.

III.12.9. Tie Benefits.

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

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

III.12.9.1. Overview of Tie Benefits Calculation Procedure.

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

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

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

III.12.9.1.2. Tie Benefits Calculation.

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

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

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

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

III.12.9.2.1. Assumptions Regarding System Conditions.

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

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

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

III.12.9.2.3. Modeling Transmission Constraints in Neighboring Control Areas.
The ISO will review annually NPCC's assumptions regarding transmission constraints in all directly interconnected neighboring Control Areas that are modeled for the tie benefits calculations. In the event that NPCC models a transmission constraint in one of the modeled neighboring Control Areas, the ISO will perform an evaluation to determine which interfaces are most critical to the ability of the neighboring Control Area to reliably provide tie benefits to New England from both operational and planning perspectives, and will model those transmission constraints in the tie benefits calculation, using the procedures in Section III.12.9.2.5.

III.12.9.2.4. Other Modeling Assumptions.

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

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

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

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

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

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

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

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

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

B. **Removing capacity from New England when the New England system is surplus of capacity.** In modeling New England as part of the interconnected system, if New England is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in these surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the existing Qualified Capacity, and any amount of proxy units added in that sub-area that is above its 50-50 peak load forecast. Notwithstanding the foregoing, if removing resources will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratios described above for the removal of capacity surplus. If there are no modeled internal transmission constraints in the New England Control Area, then the surplus capacity shall be removed from the entire Control Area.

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

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

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

III.12.9.3. Calculating Total Tie Benefits.

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

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

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

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

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

III.12.9.4.1. Initial Calculation of a Control Area's Tie Benefits.
Tie benefits from each neighboring Control Area shall be determined by calculating the tie benefits for every possible interconnection state that has an impact on the tie benefit value between the New England system and the target neighboring Control Area. If two or more interconnections between New England and the target neighboring Control Area exist, then all interconnections grouped together will be used to represent the state of interconnection between New England and the target neighboring Control Area. The tie benefits from the target neighboring Control Area shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.4.2.

III.12.9.4.2. Pro Ration Based on Total Tie Benefits.
If the sum of the individual Control Area tie benefits calculated in accordance with Section III.12.9.4.1 is different than the total tie benefits from all Control Areas calculated in accordance with Section III.12.9.3, then each Control Area's tie benefits shall be increased or decreased based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits for each individual Control Area, so that the sum of each Control Area's tie benefits, after the pro-ration, is equal to the total tie benefits calculated in accordance with Section III.12.9.3. The pro-rated Control Area tie benefits are subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.5. Calculating Tie Benefits for Individual Ties.
Tie benefits shall be calculated for an individual interconnection or group of interconnections to the extent that a discrete and material transfer capability can be identified for the interconnection or group of interconnections. All interconnections or groups of interconnections shall have equal rights in calculating individual tie benefits, with no grandfathering or incremental tie capability treatment.

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

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

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

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

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

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

III.12.9.6.1. Accounting for Capacity Imports.

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

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

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

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

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

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

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

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

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

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

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

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